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AN EXAMINATION OF BLOWOUT PREVENTION EQUIPMENT AND PROCEDURES USED ON FLOATING VESSELS

A Thesis

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Finally, to my wife Beth, to my daughters Becky and Sarah and to my parents for their love and moral support in completing this work.

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ABSTRACT

In the continuing search to find additional oil and gas accumulations, the oil industry is beginning to drill in the new frontier areas of the world. One such area is the slopes of the outer continental shelf. The outer continental shelf has already provided the industry large amounts of oil and gas reserves. A large portion of the shallow offshore ocean bottoms along the continental shelf have already been drilled in water depths in excess of 500 feet. A few wells have even been drilled in water depths in excess of 2,000 feet. At present, floating drilling vessels are being designed to drill in water depths of 6,000 feet.

As the search for petroleum reserves has moved into deeper offshore environments, well control has continued to increase in complexity. Modern well control equipment was developed mainly for land based drilling operations. This equipment is now applied with modifications to offshore drilling vessels. The purpose of this report is to locate all drilling vessels presently capable of drilling in deep water depths, and to examine the equipment carried on such vessels and procedures used in well control operations.

The initial step was to determine how many floating drilling vessels were equipped to drill in at least 2,000 feet of water. The owners of these vessels were contacted and asked to provide information on the equipment contained on each vessel. Each manufacturer of this type of equipment was then contacted to provide specific information on the sizes, working pressures, and any other pertinent data available on this equipment. The U.S. Geological Survey was then asked to provide training manuals for any operator training courses that were approved for well control training.

As a result of this investigation, it was found that there are 28 floating vessels capable of drilling in 2,000 feet of water. The same well control equipment used on land rigs is used on these floating vessels with the exception of a marine riser and a tensioning system. Also, the same training criteria and well control procedures are being taught for floating drilling vessels, regardless of water depth.

CHAPTER I

INTRODUCTION

The most costly events that have ever occurred in the history of the oil industry are losses of well control or more commonly called "blowouts". Serious losses to life, property, and the environment have been directly related to "blowouts", yet little emphasis has ever been placed on well control when embarking on new frontiers of exploration. It has taken events such as those which occurred at Spindletop and the Santa Barbara Channel to remind the oil industry of the importance of well control procedures. In a continuing search for hydrocarbon deposits or accumulations and with the increasing demand for fossil fuels imposed by the nations of the world, the oil industry is about to embark onto yet another new frontier, ie, the slopes of the outer continental shelf and the deep marine sedimentary basins of the world. If well control theory is to advance along with the technology now being developed for drilling in deeper waters, certain aspects of drilling and situations which could develop must be studied and analyzed.

At the beginning of the century, technology was such that drilling was limited to land base operations. There was no real need to explore tracts in any marine environment. Many methods of well control were developed for these land rigs. However, the only methods which were successful, all had the same general principle of keeping the bottom hole pressure constant at a value slightly above the formation pressure while pumping out a kick. The most common methods used were the "Driller's Method", the "Wait-and-Weitht Method", and the "Circulate-and-Weight Method". There are relative advantages for each method. The Driller's Method is the simplest to teach and understand. The Circulate-and-Weight Method uses a minimum of non-circulating time and requires only minimal equipment for increasing mud density. The Wait-and-Weight Method has the lowest casing and casing seat pressures and least danger of lost circulation.

In the late 1940's, the industry's search for new accumulations of petroleum had led to the shallow marine environments of the outer continental shelf. Jack-up and submersible drilling rigs were designed to drill in this type of environment. These rigs were supported by the sea bottom with the BOP equipment located on the surface. They had their drilling decks fixed in respect to the sea floor. This enabled a conductor pipe to be driven into the sea floor to provide support for a BOP stack. Both jack-ups and submersibles contained their own BOP equipment, choke and kill manifold, standpipe manifold, and piping and valve arrangement, which differed slightly from rig to rig. However, the same blowout prevention equipment, piping arrangements, and techniques used to circulate out a kick on the land rigs were applied to the jack-ups and submersibles. As time progressed drilling activity expanded into deeper water depths. Eventually, water depth was the limiting factor for both the jack-up and the submersible rigs. Most of these rigs could not drill in water depths beyond 300 ft.

By the early 1960's, semisubmersible rigs and drillships were developed that could drill from a floating position. With the advent of floating vessels, the BOP stack could no longer be fixed to the conductor pipe at a surface location. The continuous motion of the floating vessels in the deeper waters required that the blowout preventers be installed on the ocean floor. In addition, emergency conditions, usually adverse weather, might force a rig to suspend operations or move off location. With the BOP stack and wellhead on the ocean floor the marine riser could be removed with little danger of damage to the well.

In 1974, Shell Oil Company drilled the first well in 2,000 feet of water.[1] In the summer of 1979 Texaco Canada drilled a well off the coast of Newfoundland in 4876 feet.[2] Figure 1.1 illustrates how rapidly the industry is progressing into deeper water depths.[3] The oil industry is not only continuing to set water depth records, but the number of deep water wells is steadily increasing. This trend is shown by Figure 1.2.[3] In 1980, nineteen wells were drilled in waters deeper than 2,000 feet.[3]

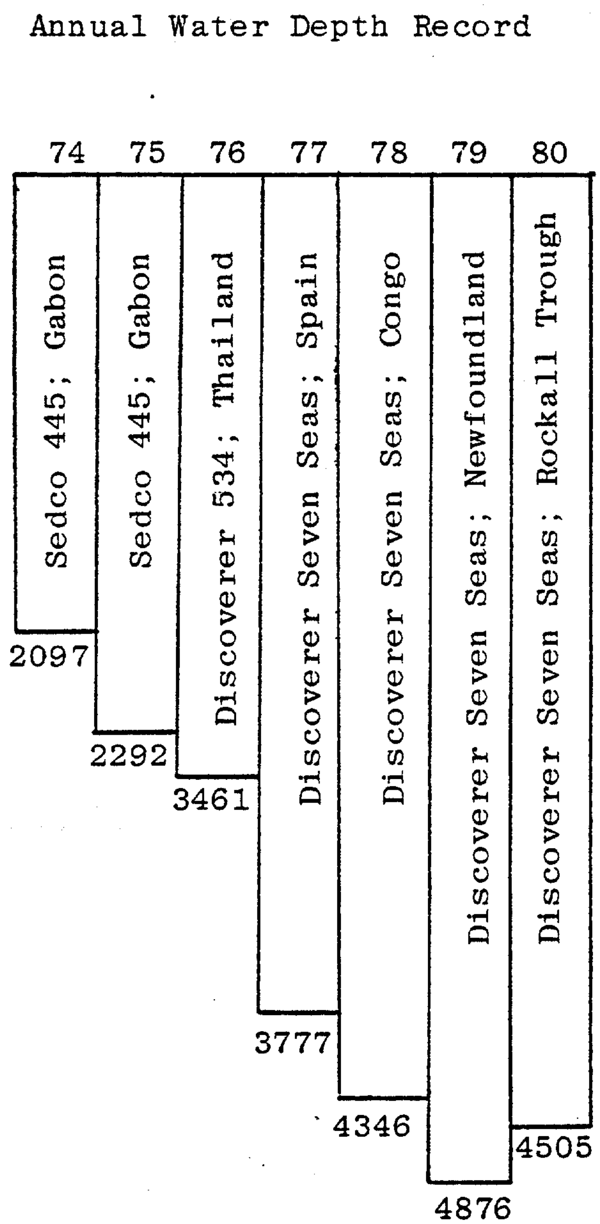

Figure 1.1 - Annual Water Depth Record[3]

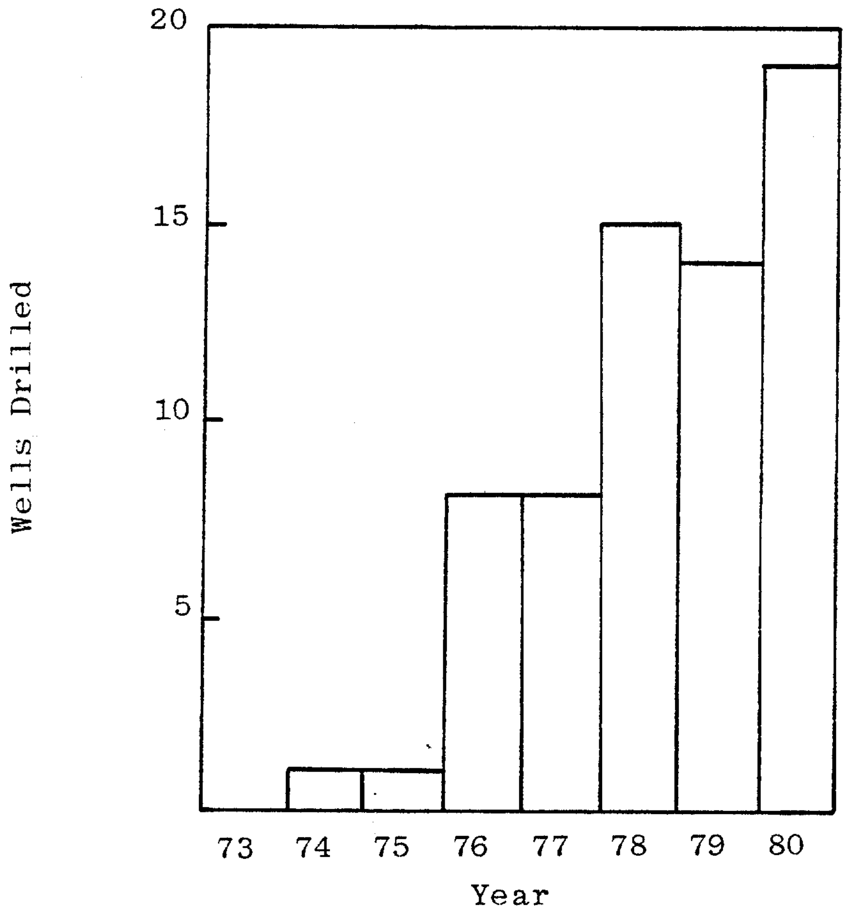

Figure 1.2 - Annual Number of Wells Drilled[3]
in Over 2,000 Feet of Water

Drilling from a floating vessel has opened up many problem areas which should be investigated. One such problem area is in well control procedures. The techniques of well control developed for land based drilling rigs are still being employed on floating vessels. Choke and kill lines are still being utilized for mud returns and adjustable choke valves are used to maintain constant bottom hole pressures. By placing the BOP stack on the sea floor and running the choke and kill lines from the sea floor back to the surface, the frictional pressure drops occurring in these lines become quite significant as water depths increases.

The primary objectives of this report are to identify the floating drilling vessels capable of drilling in 2,000 feet of water or deeper, and to inventory the well control equipment contained on these drilling vessels. In addition, the current well control procedures employed during a well control operation will be examined. Future studies will utilize the information and data gathered by this study to address the specific well control problem areas.

CHAPTER II

SURVEY OF DEEP WATER DRILLING VESSELS

Every second year a "Directory of Marine Drilling Rigs" is produced by Gulf Publishing Company[4]. This directory includes all available marine drilling rigs, ie, barges, submersibles, jack-ups, semisubmersibles, and drillships. It was through the use of this directory, that the rig owners were contacted.

2.1 Deep Water Rig Availability.

Glancing at the "Directory of Marine Drilling Rigs[4]", one could infer that there is an abundant supply of marine rigs available. Four hundred and sixty three rigs are listed along with their specifications and descriptions and description. However, reviewing specifications for those rigs capable of drilling in deep waters indicates how limited the selection becomes. Drilling barges, submersible and jack-up rigs are all limited by water depth. Most submersible rigs are restricted to a maximum water depth of 75 feet of water; and most drilling barges are limited to 110 feet of water. The maximum water depth of jack-up rigs is about 300 feet of water. This leaves us with just two types of rigs capable of drilling in water depths of 300 feet or deeper, semisubmersibles and drillships.

Most semisubmersibles were constructed to operate on the outer continental shelf. This is generally considered to be in water depths approaching 600 to 800 feet. Only a small percentage of the semisubmersibles are equipped to drill in deeper waters. There are only 67 semisubmersible rigs equipped to drill in 1,000 feet of water. Only 11 semisubmersibles are capable of drilling in water depths greater than 2,000 feet. Table 2.1 lists these vessels.[4]

There are even fewer drillships available to the industry. Of the 75 drillships, only 17 are equipped to drill in water depths greater than 2,000 feet. Table 2.2 is a listing of these drillships.[4]

Figure 2.1 illustrates the significant reduction of floating drilling vessels available for drilling in deep waters. In all there are only 28 drilling vessels worldwide capable of drilling in 2,000 feet of water or deeper.

2.2 Survey Sample.

Of the 28 drilling vessels equipped to drill in deep waters, 7 are owned and operated by foreign companies. Fifteen are owned by 4 American companies. The remaining 6 vessels are individually owned by 6 American companies. By elimination of the foreign owned vessels, and concentrating on the American owned vessels, 22 vessels remained

Table 2.1 - Semisubmersibles Capable of Drilling in Water Depths of 2,000 Feet or Deeper[4]

Rig Owner	Rig Name	Maximum Depth
Fearnley Drilling & Expl.	Fernstate	3,000
Keydrill Company	Aleutian Key	2,000
Marine Drilling S. A.	Sedco 709	6,000
Penrod Drilling Company	Penrod 74	2,000
Sedco Inc.	Sedco 703	2,000
Western Ocianic/Exxon	Alaskan Star	2,000
Zapata Corp.	Zapata Concord	2,000
Zapata Corp.	Zapata Lexington	2,000
Zapata Corp.	Zapata Saratoga	2,000
Zapata Corp.	Zapata Ugland	2,000
Zapata Corp.	Zapata Yorktown	2,000

Table 2.2 - Drillships Capable of Drilling in Water Depths of 2,000 Feet or Deeper[4]

Rig Owner	Rig Name	Maximum Depth
Amoshore Drilling Company	Discoverer 511	2,000
Global Marine Inc.	Glomar Atlantic	2,000
Global Marine Inc.	Glomar Challanger	20,000
Global Marine Inc.	Glomar Pacific	2,000
Helmer Stanbo & Co.	Pelerin	3,300
Marine Drilling & Coring Co.	Candrill I	5,000
Neddrill (Nederland) B.V.	Nedrill	6,000
ODECO/Ben Line Offshore	Ben Ocean Lancer	3,000
The Offshore Company	Discoverer II	2,000
The Offshore Company	Discoverer 534	3,000
The Offshore Company	Discoverer Seven Seas	4,500
Offshore Europe N.V.	Petrel	3,000
Overseas Drilling Ltd.	Sedco/BP 471	4,500
Pacnorse Drilling Corp.	Pacnorse I	3,000
Saipern	Saipern Due	2,000
Sedco Inc.	Sedco 445	3,500
Sedco Inc.	Sedco 472	4,500

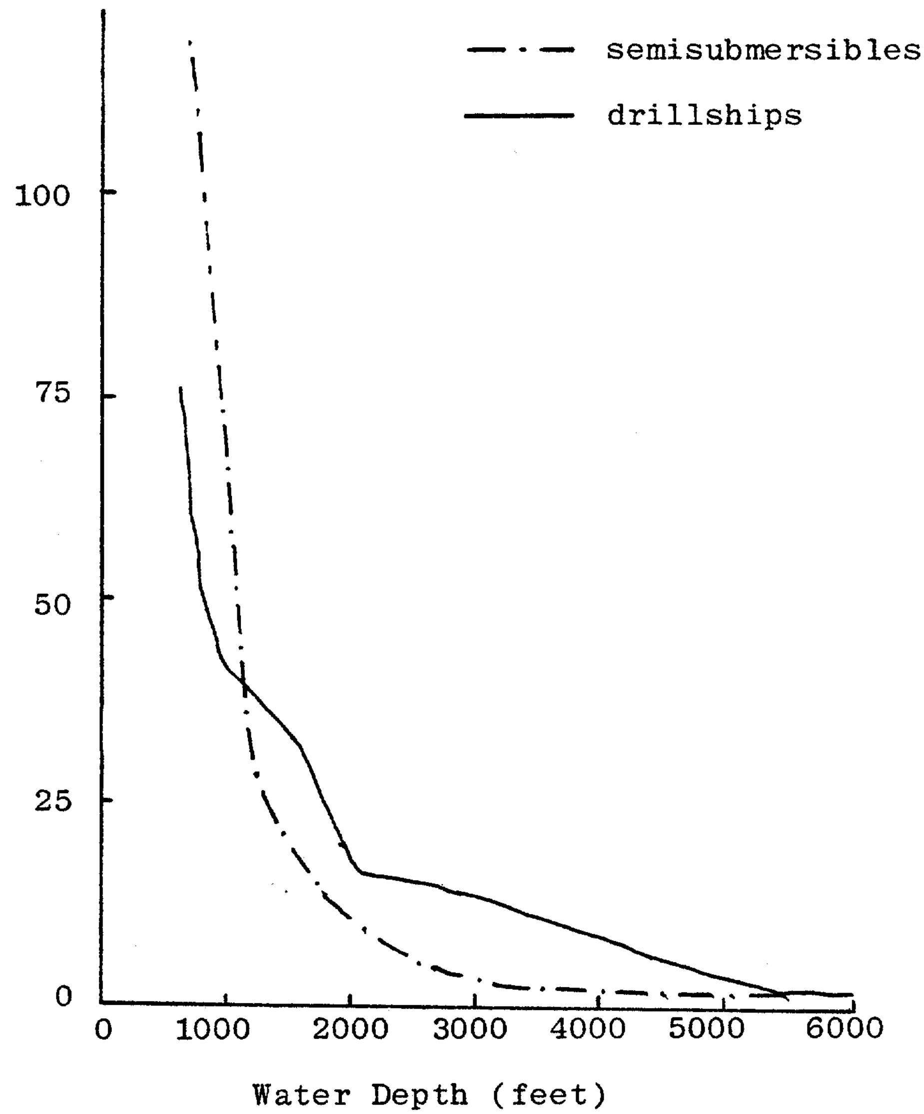

Figure 2.1 - Drilling Vessels Available for Drilling in Deep Waters[4]

that were capable of drilling in deep water; only 9 of those have actually drilled in water depths exceeding 2,000 feet.

Through 1980, only 66 wells have been drilled in water depths of 2,000 feet or deeper.[3] Table 2.3 lists these wells by year giving the location and drilling vessel used to drill each well. Table 2.4 shows the number of wells that each vessel has drilled in 2,000 feet of water or deeper. The Discoverer Seven Seas, the Sedco 472, and the Sedco 445 have drilled over half of the deep water wells. The Discoverer Seven Seas hold the water depth record for the well drilled by Texaco Canada off the shore of Newfoundland in 4,876 feet of water.[2]

The owners of these 9 American owned drilling vessels were contacted for information concerning their rigs.

2.3 Survey Results.

All 9 of the rig owners contacted responded by supplying brochures containing the equipment carried on each of their rigs. Some of this literature was more descriptive than others, but all contained information on the subsea equipment used. Besides these 9 drilling vessels, equipment information on the "Pelerin" a foreign owned vessel, appeared in one of the trade journals.[5] Using the equipment description for these 10 drilling vessels, the equipment manufacturers were contacted to submit information concerning their subsea equipment. All of these equipment

Table 2.3 - Listing of Wells Drilled in 2000 Feet of Water or Deeper[3]

Operator	Well Location	Rig Name	Water Depth (in feet)
	1980		
BNOC	Rockall Trough, 16376-1	Discoverer Seven Seas	4505
Esso Australia	Australia, Vinck-1	Sedco 472	4504
Esso Australia	Australia, N.W. Shelf	Sedco 472	4500
Esso Australia	Exmouth Plateau	Sedco 472	4473
Esso Australia	Exmouth Plateau	Sedco 472	3881
Phillips Petroleum	Exmouth Plateau	Sedco/BP 471	3864
Esso Australia	Australia, Sirius-1	Sedco 472	3851
Hispanoil	Mauratania, Ras al Baida	A-1 Discoverer Seven Seas	3672
Woodside Pet.	Exmouth Plateau	Sedco/BP 471	2933
AGIP	Aquila, Italy	Discoverer Seven Seas	2713
Chevron Spain	Montanazo D-3, Spain	Pacnorse I	2650
Woodside Pet.	Exmouth Plateau	Sedco 445	2640
Esso Australia	West Australia	Sedco 472	2526
Esso Australia	Exmouth Plateau	Sedco 472	2430
Esso Australia	Zeepaard, Australia	Sedco 472	2426
Woodside Pet.	West Australia	Sedco 445	2400
Phillips Petroleum	Miss. Canyon, OCSG-4135 #1	Zapata Concord	2150
Woodside Pet.	Exmouth Plateau	Sedco 445	2079
Shell Expro.	West Shetlands 206/2-1	Petrel	2004
	1979		
Texaco Canada	Newfoundland, Texaco Shell et al Blue H-28	Discoverer Seven Seas	4876
Eniepsa	Spain, Cabriel B-2	Discoverer Seven Seas	4589
Getty Oil	Spain, Grumete C 1X	Discoverer Seven Seas	4411
Esso Australia Ltd.	Australia, Zeewulf-1	Sedco 472	3920
Phillips Petroleum	Australia, Exmouth Plateau Mercury IX	Sedco 471	3746
Esso Resources Ltd.	Canada, EVG C-60	Sedco 709	3636
Esso Australia Ltd.	Australia, Resolution-1	Sedco 472	3565
Esso Resources Ltd.	Canada EHB Gjoa G-37	Sedco 709	3276
Phillips Petroleum	Australia, Exmouth Plateau Jupiter No.1	Sedco 471	3070

Table 2.3 (continued)- Listing of Wells Drilled in 2000 Feet of Water or Deeper[3]

Operator	Well Location	Rig Name	Water Depth (in feet)
	1979 continued		
Esso Australia Ltd.	Australia, Scarborough-1	Sedco 472	2992
Phillips Petroleum	Ghana, So. Dix Cover IX	Discoverer Seven Seas	2927
Esso Australia Ltd.	Australia, Investigator-1	Sedco 472	2758
Chevron	Baltimore Canyon, Cost B-3	Ben Ocean Lancer	2687
Chevron	Gambia	Pelerin	2295
	1978		
Getty Oil	Pointe Noire, Congo	Discoverer Seven Seas	4346
Esso Expl. Guyane S.A.R.L.	French Guiana, FG 2-1	Sedco 472	4100
Esso Expl. Surinam Inc	Surinam, A 2-1	Sedco 472	3806
Hispanoil/Eniepsa	Gulf of Valencia	Discoverer Seven Seas	3755
Chevron	Montanazo C-1	Ben Ocean Lancer	3209
AGIP	Adriatic, Rovesti 1	Discoverer Seven Seas	3133
Total	Kenya, Simba 1	Pelerin	3019
Total/Kenya SNEA	Kenya	Pelerin	3018
CFP	Algeria, Habibas	Pelerin	3001
Phillips	Ghana, South 1-X	Discoverer Seven Seas	2947
Chevron Standard	Nova Scotia, Acadia K-62	Ben Ocean Lancer	2841
Shell Teoranata	West Coast of Ireland 35/29-1	Sedco 709	2638
Chevron Overseas	Spain, Montanazo D-2	Ben Ocean Lancer	2467
Hipco of New Zealand	So. Island, New Zealand	Penrod 74	2300
Chevron Overseas	Spain, Montanazo C-1	Ben Ocean Lancer	2209
	1977		
Eniepsa	Spain, Ibiza Marino AN-1	Discoverer Seven Seas	3777
Total Algeria	Algeria-Habibas 1	Pelerin	3038
Esso Egypt	Red Sea, RSO T'95-1	Discoverer 534	2737
Esso Egypt	Red Sea, RSO Z'95-1	Discoverer 534	2506
Hipco of New Zealand	So. Island, New Zealand	Penrod 74	2250
Hipco of New Zealand	So. Island, New Zealand	Penrod 74	2247
Hipco of New Zealand	So. Island, New Zealand	Penrod 74	2100
Wepco	Egypt Quseir Well	Discoverer Seven Seas	2060

Table 2.3 (continued)- Listing of Wells Drilled in 2000 Feet or Water or Deeper[3]

Operator	Well Location	Rig Name	Water Depth (in feet)
	1976		
Esso Exploration	Thailand, W9-E1	Discoverer 534	3461
Esso Exploration	Thailand, W9-C1	Discoverer 534	2959
Esso Exploration	Red Sea, RSO T'95-1	Discoverer 534	2737
Esso Exploration	Thailand, W9-DI	Discoverer 534	2652
Esso Exploration	Thailand, W9-B1	Discoverer 534	2632
Union Oil of Thailand	West Thailand	Sedco 445	2039
Union Oil of Thailand	West Thailand	Sedco 445	2028
Union Oil of Thailand	West Thailand	Sedco 445	2017
	1975		
Shell	Gabon	Sedco 445	2292
	1974		
Shell	Gabon	Sedco 445	2097

Table 2.4 - Number of Wells Drilled in 2,000 Feet of Water or Deeper per Drilling Vessel[3]

Rig Name	Number of Wells Drilled
Sedco 472	14
Discoverer Seven Seas	13
Sedco 445	8
Discoverer 534	7
Ben Ocean Lancer	5
Pelerin*	5
Sedco/BP 471	4
Penrod 74	4
Sedco 709	3
Pacnorse*	1
Zapata Concord	1
Petrel*	1
	66

* Foreign Owned Vessel

manufacturers responded by sending equipment catalogs. These equipment catalogs contained information on dimensions, weights, and pressure ratings for the various components, which will be described in the next chapter.

Under the laws established for drilling in U.S. federal waters, drilling rig personnel must be trained in well control procedures from an approved U.S.G.S. training course.[6] This topic will be discussed in Chapter IV. Eleven courses are conducted within individual oil companies and have been approved by the Geological Survey. The training manuals for these 11 operator courses were requested from the Geological Survey. Because the volume of the materials requested was too great to send by mail, only four manuals were obtained. The Geological Survey assured that these manuals are typical course manuals and should provide a representative sample of an operators itinerary.

2.4 Typical Piping Diagrams.

In addition to the equipment information gathered on the 10 drilling vessels that have already drilled in 2,000 feet of water or deeper, piping diagrams of the well control equipment used on the Alaskan Star and the Zapata Concord were obtained. These rigs happened to be drilling in the Gulf of Mexico at the time of this study, and were available for a personal inspection. Both of these rigs are capable of drilling in deep waters, and the Zapata Concord has already drilled a well for Phillips Petroleum in the Mississippi Canyon in a water depth of 2,150 feet.[3] The operators of the Alaskan Star and the Zapata Concord were contacted and arrangements were made to tour these rigs. The equipment contained on these vessels and all the piping and valve arrangements were visually inspected. Rig personnel provided schematic diagrams of the choke and kill manifold, standpipe manifold, and flow diagrams. While the actual placement of these manifolds varied according to the rig layout, the flow path and valve arrangements were the same. All the piping and valves on the rigs were permanently attached to the rig structure. Figures 2.2 thru 2.6 are flow diagrams of the piping and valve arrangements of the high pressure mud return system used on the Zapata Concord. Figure 2.7 shows the same piping and valve arrangement used on the Alaskan Star. Both of these flow paths are similar in that flow may be directed from the choke and kill lines through a manifold to either the shale shaker, the mud/gas separator, the flare or vent lines, or to the standpipe manifold. Flow may also be directed from the mud pumps or cement pumps through the choke and kill manifold down either the choke or kill line or both, and into the wellbore annuli. The manifolds on the various components, ie, choke and kill, standpipe, or cement manifolds, provide almost any flow path desired in a well control operation. These flow paths are typical of any floating drilling vessel using a subsea BOP stack assembly.

Figure 2.8 is a similar flow diagram while utilizing

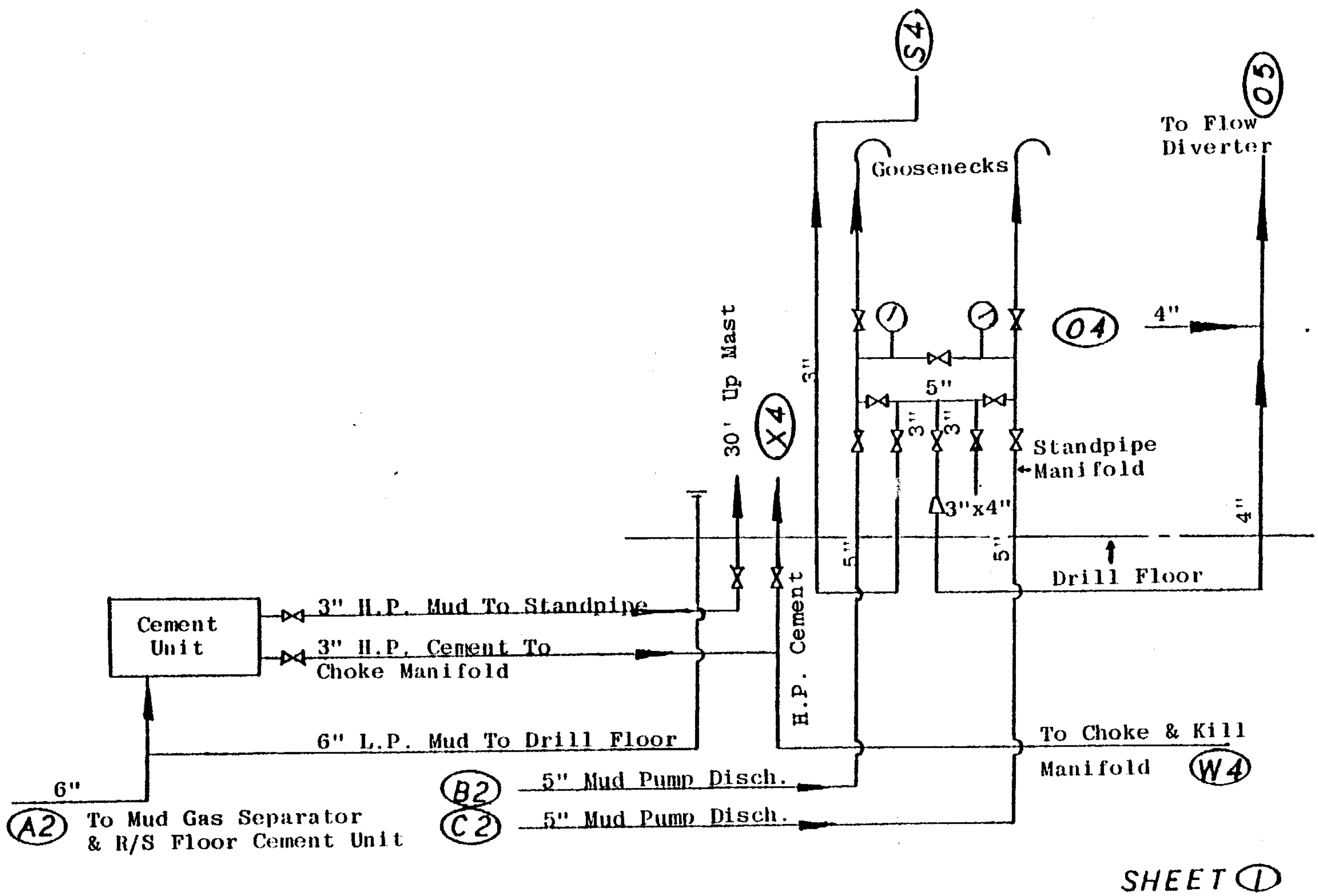

Figure 2.2 - Standpipe & Cement Unit on Zapata Concord

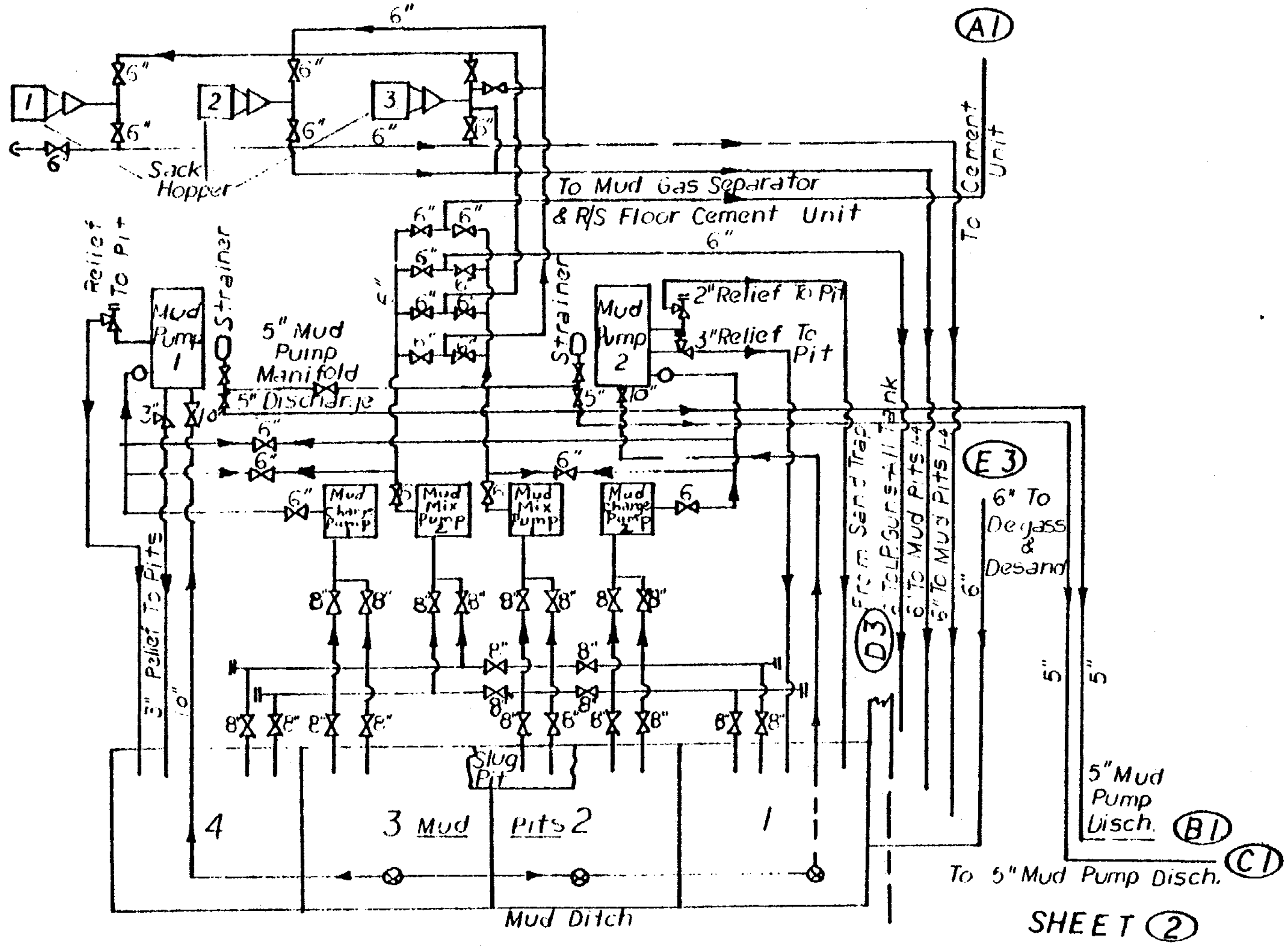

Figure 2.3 - Mud Pump Piping on Zapata Concord

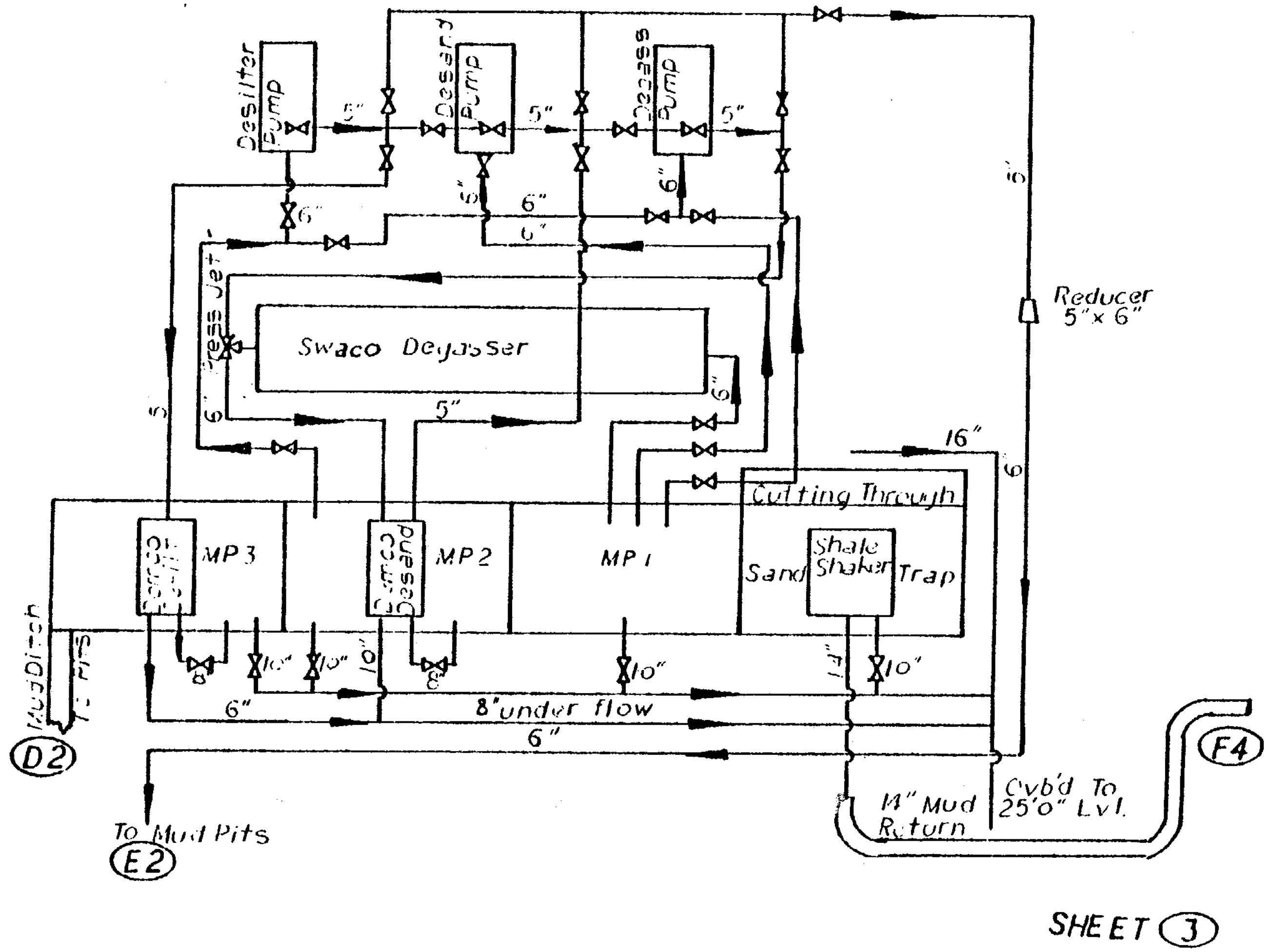

Figure 2.4 - Shale Shaker & Sand Traps on Zapata Concord

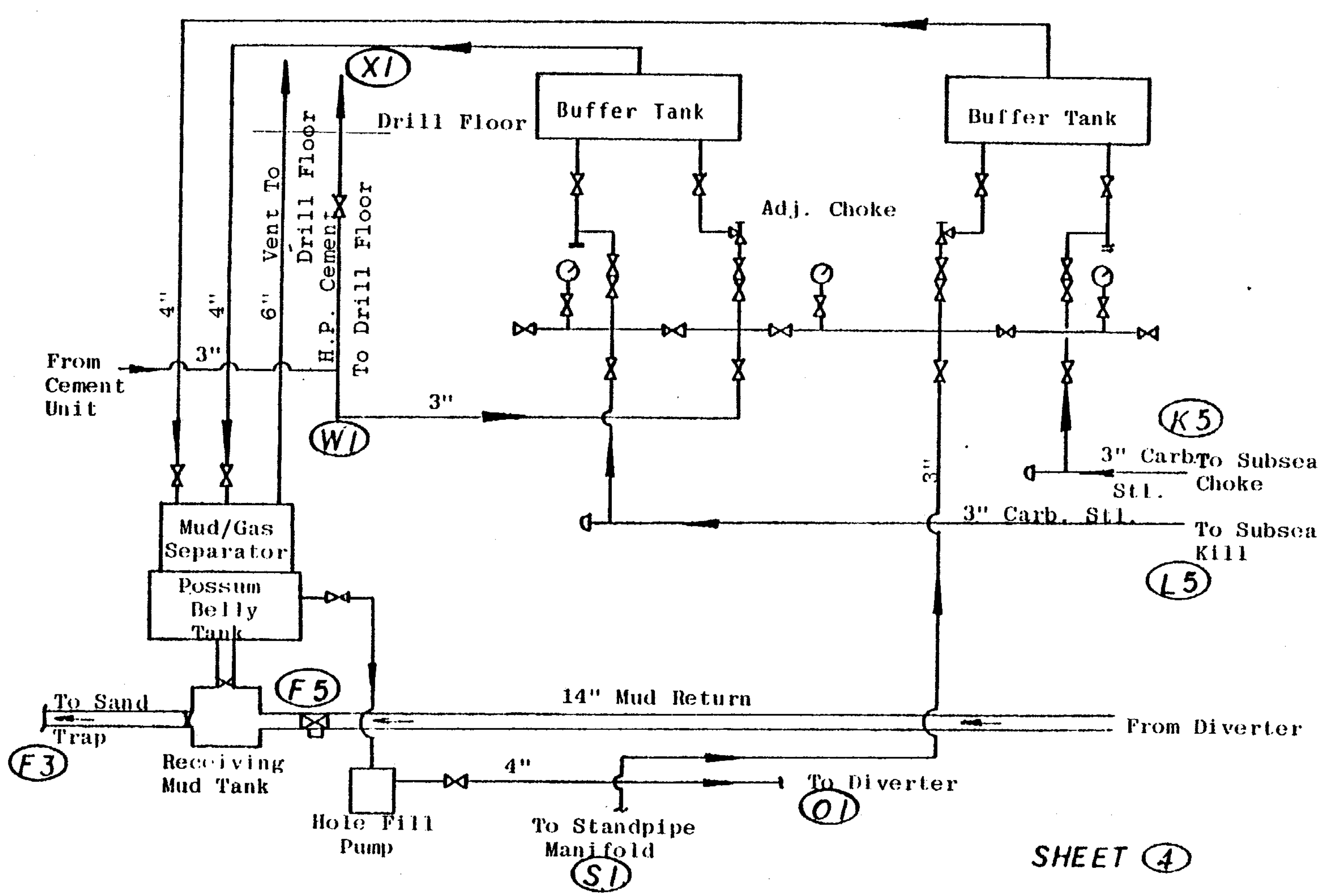

Figure 2.5 - Choke Manifold & Mud/Gas Separator on Zapata Concord

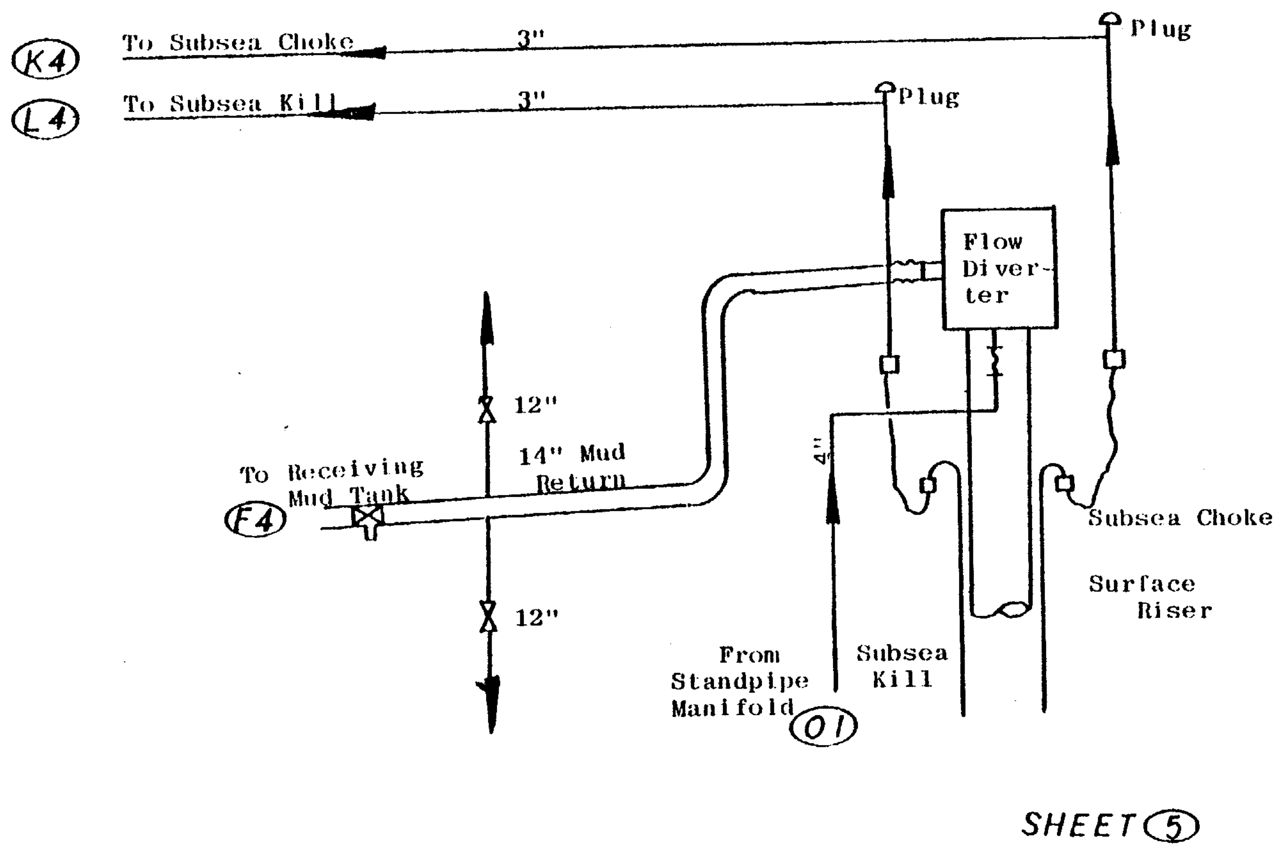

Figure 2.6 - Diverter System & Trip Tank on Zapata Concord

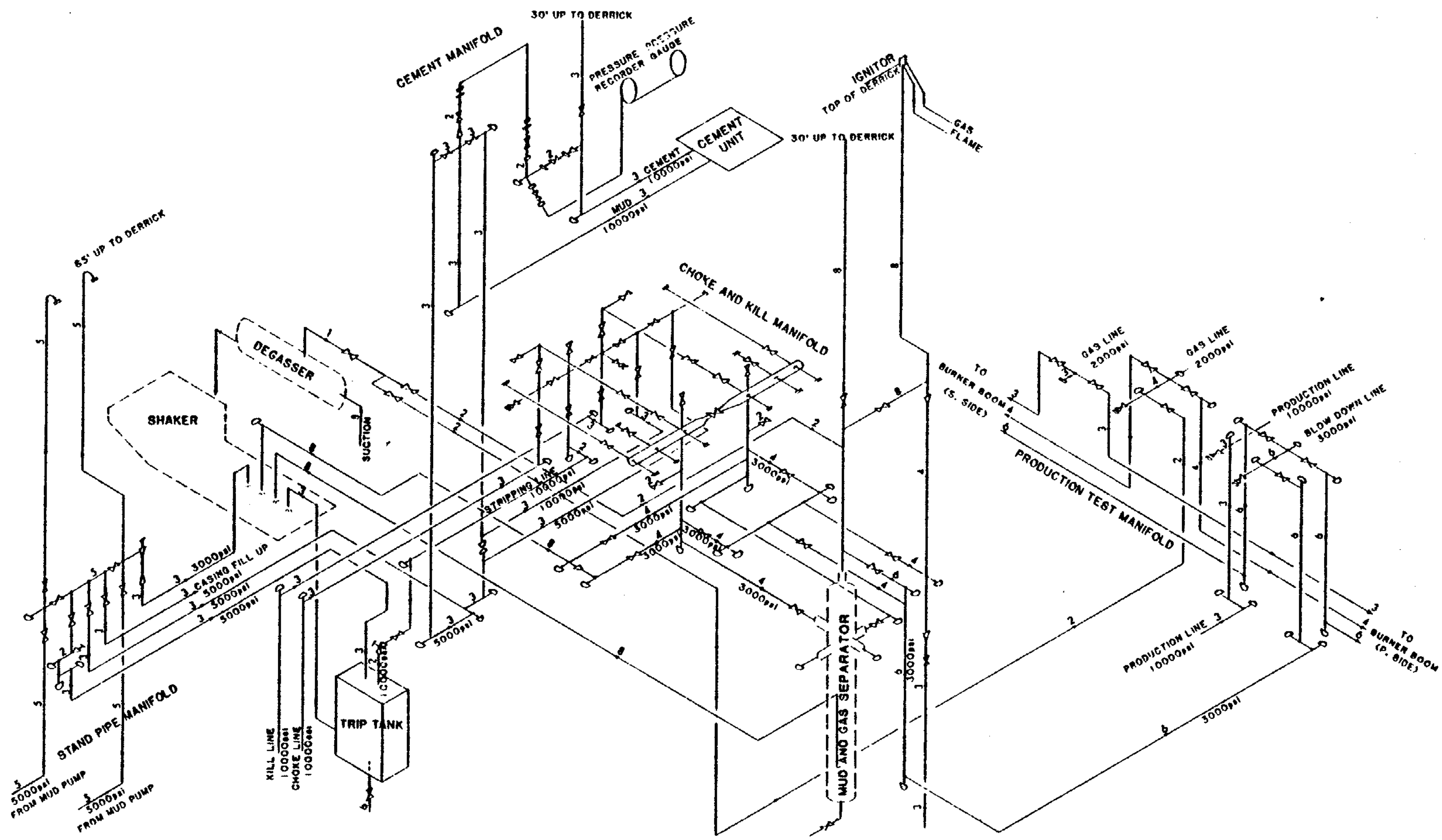

Figure 2.7 - Alaskan Star Piping Arrangement

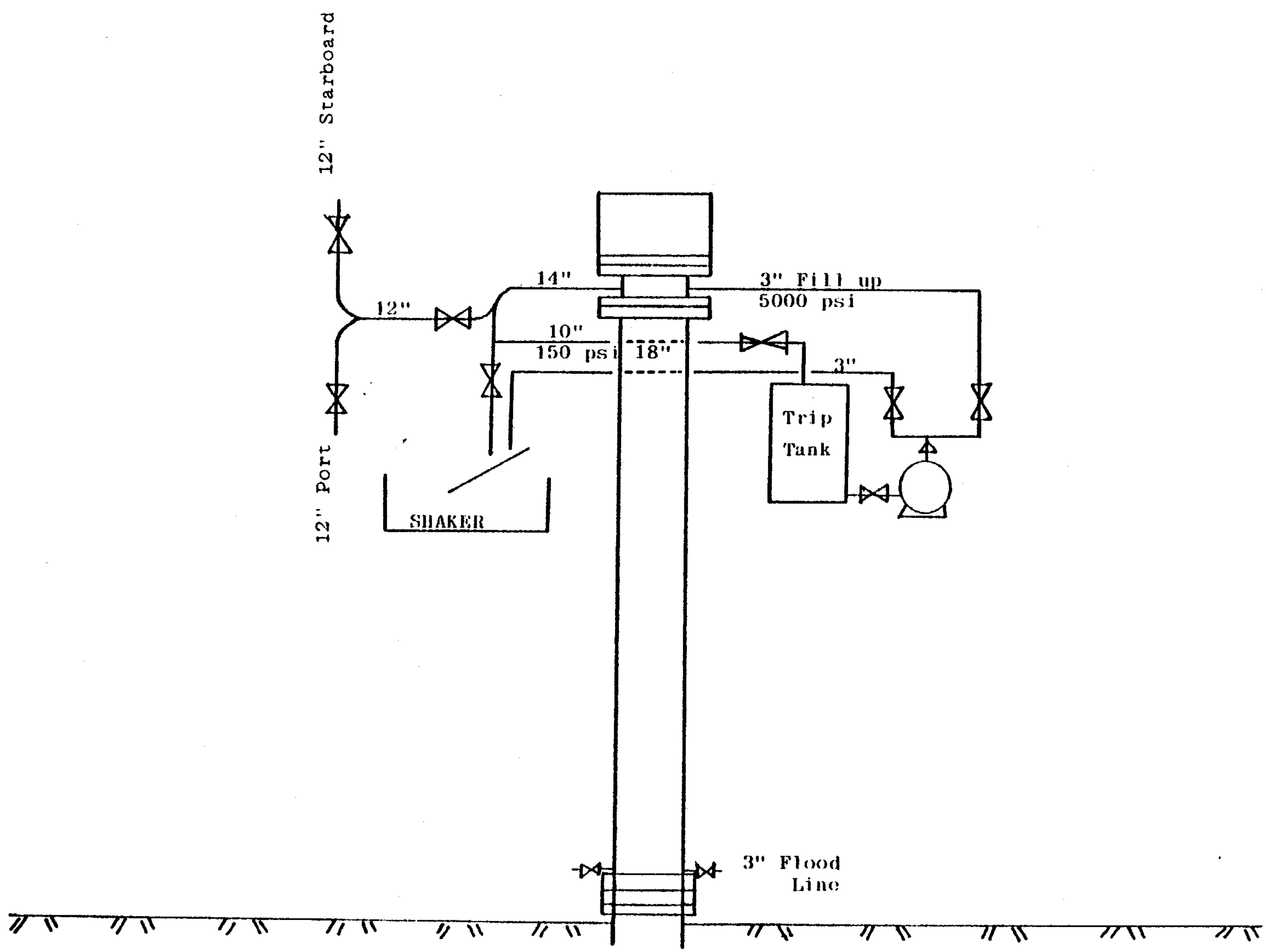

Figure 2.8 - Typical Flow Diverter System

a diverter system. Low pressure flow may be directed to either a port or a starboard vent line, a trip tank, or the shale shaker, depending on the situation encountered.

CHAPTER III

DESCRIPTION OF AVAILABLE WELL CONTROL EQUIPMENT

The well control equipment used on floating drilling vessels is available from only a limited number of suppliers. The equipment used for well control, such as blowout prevention equipment, riser systems, and diverter systems were custom designed for the drilling industry. Consequently, only the major oil field suppliers entered the market for well control equipment. Existing floating drilling vessels have unique piping and valve arrangements dictated by the general layout of the rig itself. However, the well control equipment used on these rigs can only be obtained from this limited number of suppliers.

The well control system consists of the following components (1) The Blowout Preventer Stack, (2) The Control System, (3) The Marine Riser, (4) The Diverter System, and (5) The Choke and Kill Manifolds. The following sections will discuss the types of equipment used on floating drilling vessels and any government regulations or API recommended practices that are applicable.

3.1 The Blowout Preventer Stack

The subsea Blowout Preventer (BOP) stack as discussed herein will consist of (1) a guidebase, (2) a subsea wellhead assembly, (3) various combinations of ram-type and annular-type blowout preventers, and (4) a lower marine riser connector. Fifty-eight (58) of the sixty-six (66) wells drilled in deep water, were drilled by rigs employing a guidelineless drilling system.[3] Drilling without guidelines utilizes a temporary guidebase attached directly to the sea floor, to which a permanent guidebase can be aligned.

3.1.1 A Guidebase

The temporary guidebase consists of a large diameter reentry funnel with a flat bottomed base mounted on top of a caisson. The funnel is cone shaped to provide easy reentry of tools into the borehole and guiding the stack into the wellhead. It provides for landing of subsequent casing string and the wellhead assembly. Four sonar reflectors are positioned around the periphery of the base on extension arms. Figure 3.1 illustrates a temporary guidebase.[7]

The permanent guidebase, Figure 3.2, consists of a large diameter funnel with gimbal pads on the underside.[7] The gimbal pads are designed to land on the funnel of the temporary guidebase and allow the permanent guidebase to set level. At the base of the permanent guidebase is a profile for accepting the conductor housing. A diverter assembly can be installed to divert returns and cuttings out through the discharge lines away from the base template. Vetco Offshore Group and National Supply Co. are the major suppliers of guidebases.

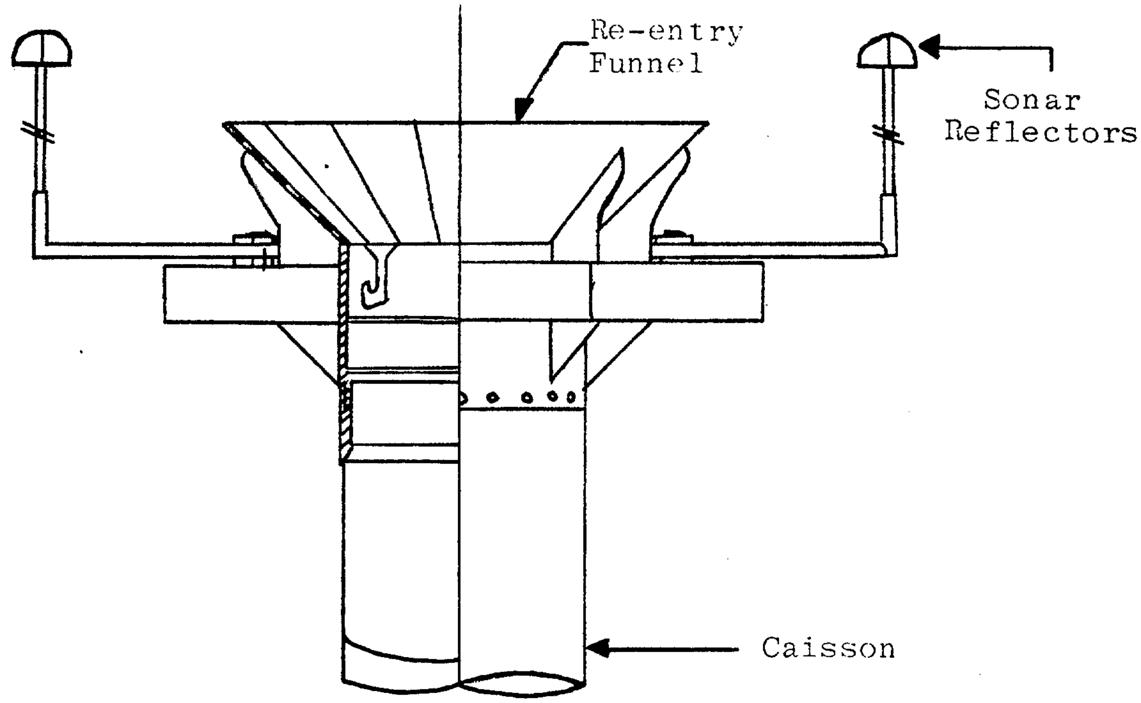

Figure 3.1 - Temporary Guidebase[7]

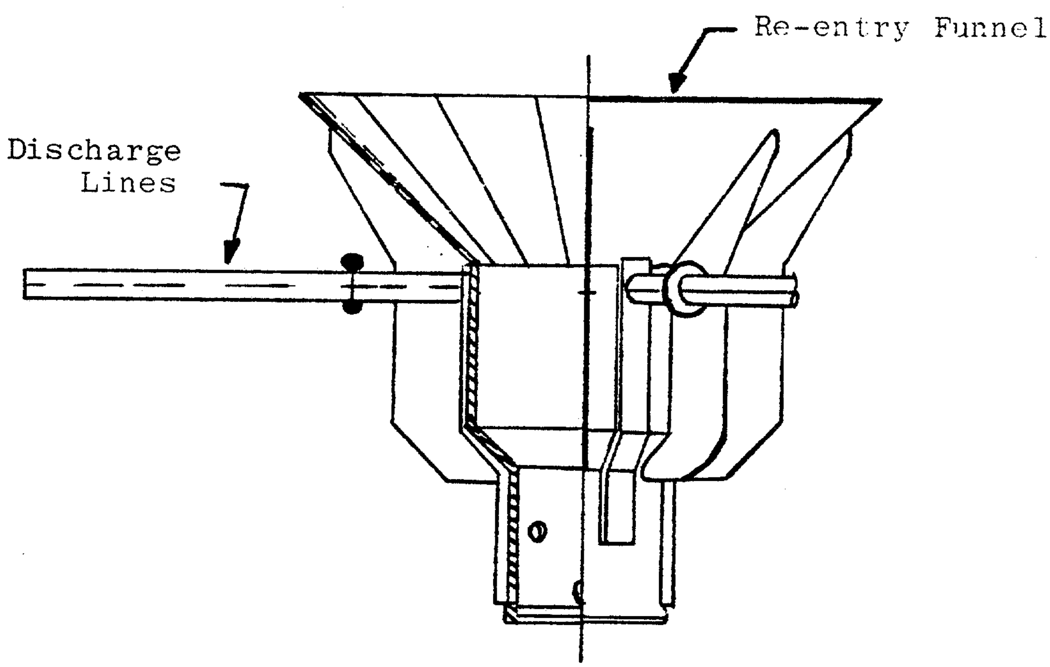

Figure 3.2 - Permanent Guidebase[7]

3.1.2 A Subsea Wellhead Assembly

The wellhead is the starting point for most blowout-preventer assemblies. It is a vital link between the casing and the preventer equipment. The surface casing is nearly always welded to the wellhead housing. Subsequent casing strings are then run using the well-housing for support. Figure 3.3 illustrates a subsea wellhead system.[8] The wellhead housing also provides a pressure seal and hold down arrangement between the surface casing and BOP stack. There are many suppliers for subsea wellhead assemblies, such as B.J. Hughes, Cameron Iron Works, National Supply Co., Regan Offshore, and Vetco Offshore.

3.1.3 Various Combinations of Ram-type and Annular-type Blowout Preventers

Blowout preventers for a floating drilling rig serve the same purpose as conventional land drilling. They provide a means of pressure control when an undesired flow develops, and they provide for circulating and conditioning the drilling fluid during a flow condition. The blowout preventer stack must also permit:

1. sustained circulation under pressure for prolonged periods of time;
2. such actions as hanging off the drill pipe, closing in the well, and moving the drill vessel off location;
3. the reestablishment of the drill vessel on location and the monitoring and reestablishment of circulation down the drill pipe; and

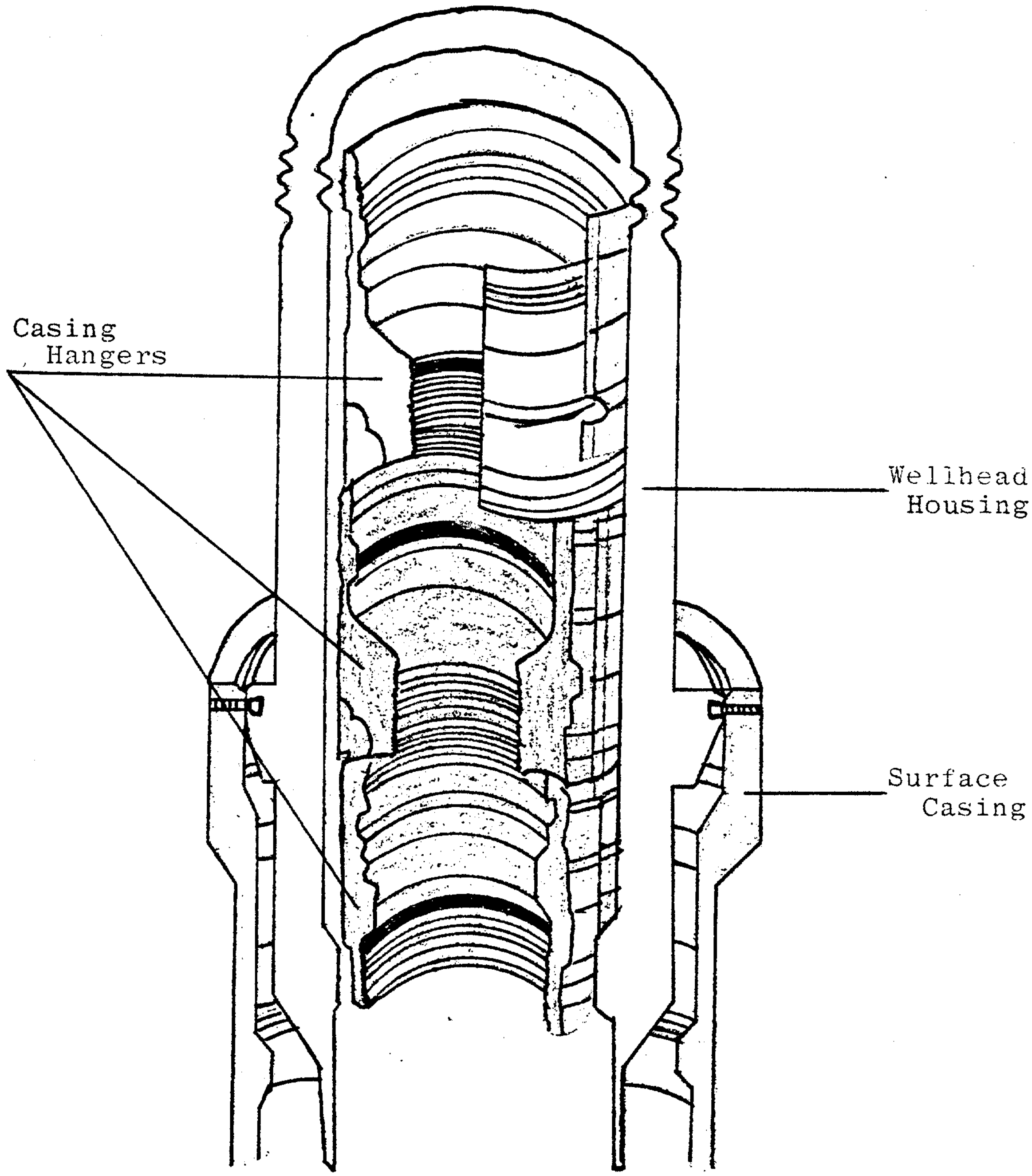

Figure 3.3 - Wellhead System[8]

4. alternate methods of well control in case of failure of any part of the BOP stack.

Any assembly of blowout prevention equipment must be rated by the lowest pressure-rated item in the hookup, whether it is the casing, casing-head, preventers, or the other fittings exposed to pressure. The BOP equipment used on the rigs surveyed were rated at 10,000 psi, and were either 18-3/4 inches or 16-3/4 inches in size. Table 3.1 is a listing of the rigs surveyed giving the size and pressure ratings of the BOP equipment on each.

A typical subsea BOP stack contains four ram-type preventers and two annular-type preventers. The arrangement of these preventers is determined by the oil company to which the rig is contracted, but the most commonly used arrangements are shown in Figure 3.4. These two arrangements are those recommended by the API in Recommended Practice No. 53.[9] The arrangements of subsea blowout preventer stacks are similar to the typical surface installations with certain differences. The differences are:

1. Choke and kill lines normally are connected to ram preventer body outlets.

2. Spools may be used to space preventers for shearing tubulars, hanging off drill pipe, or stripping operations.

3. Choke and kill lines are manifolded for dual pur-

Table 3.1 - Size and Pressure Ratings of BOP Equipment on Rigs Surveyed

Rig Name	Size(in.)	Pressure Rating(psi)	Choke & Kill ID (inches)	Number of Subsea Lines
Ben Ocean Lancer	16-3/4	10,000	3.5	2
Discoverer Seven Seas	16-3/4	10,000	3.152	2
Discoverer 534	16-3/4	10,000	2.728	2
Pelerin	16-3/4	10,000		
Penrod 74	18-3/4	10,000	2.5	2
Sedco 445	16-3/4	10,000	3.0	2
Sedco/BP 471	16-3/4	10,000	3.0	2
Sedco 472	16-3/4	10,000	3.0	2
Sedco 709	16-3/4	10,000	3.0	2
Zapata Concord	18-3/4	10,000	2.4	2

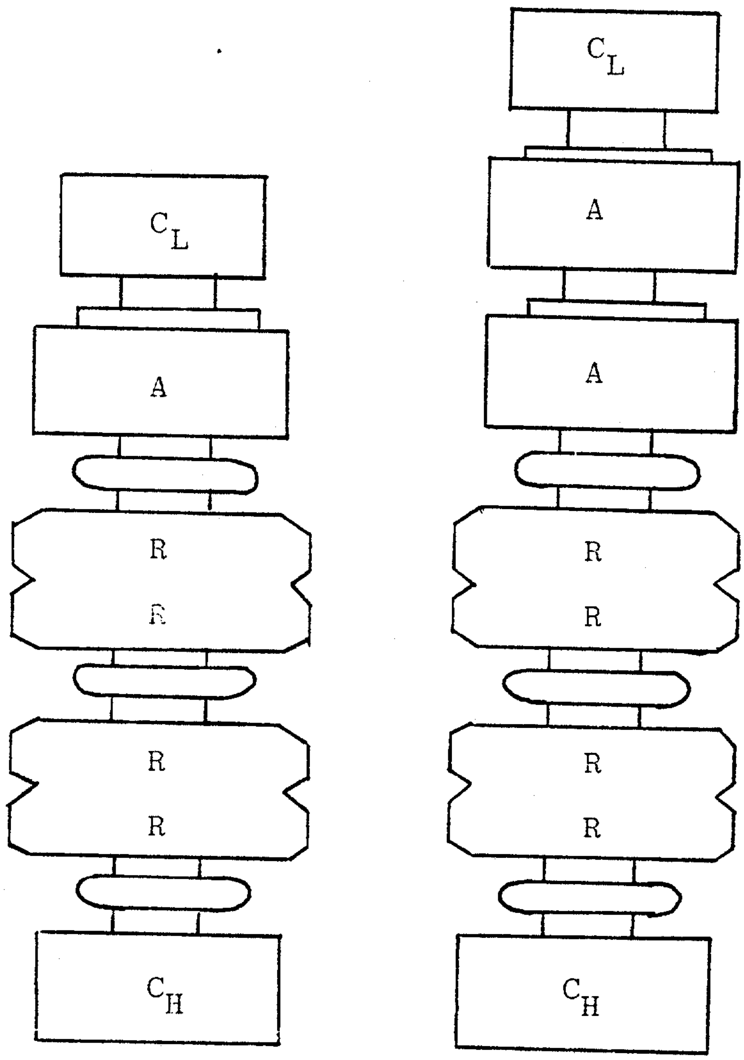

Figure 3.4 - Most commonly used preventer arrangements.[9]
(API RP53)

A = annular-type blowout preventer

R = ram-type preventer

C_H = remotely operated high pressure connector used to attach wellhead or preventers to each other.

C_L = remotely operated low pressure connector used to attach marine riser to the blowout preventer stack.

pose usage.

4. Blind/shear rams are normally used in place of blind rams.

5. Ram preventers are usually equipped with an integral or remotely operated locking system.

Ram-type BOPs for subsea service differ only slightly from those used on land. The primary difference is the addition of a remote ram-locking device. As one might expect, the same companies that supply the ram-type BOPs also supply the subsea BOPs. Cameron Iron Works, Hydril Company, and NL Rig Equipment are the largest suppliers of this type of equipment. Tables 3.2 and 3.3 contain a listing by manufacturers of the various dimensions and weights for ram-type blowout preventers.[10-12] Eight of the rigs surveyed were equipped with Cameron ram "type U" preventers. The other 2 rigs did not indicate the manufacturer of their ram preventers. The ram-type preventers must be fitted with rams that fit the size pipe in the hole and can not be used except on round shapes. It is absolutely vital that the pipe rams in a blowout preventer stack fit the pipe that is in use. If more than one size of pipe is in use U.S.G.S. OCS Order No. 2[6] requires that a second ram-type preventer be in the stack in order to have both sizes of rams available for instant use. In subsea applications, ram-locking is accomplished hydraulically. Many of the rigs surveyed also had acoustic backups for closing the BOP's. When rams have been locked in the closed position, loss of hydraulic

Table 3.2 - Listing of Dimension and Working Pressures by Manufacturers for Single Ram-type Preventers

	CAMERON IRON WORKS[10]			N L RIG EQUIPMENT[11]			HYDRIL[12]	
Size	16-3/4	16-3/4	18-3/4	16-3/4	16-3/4	18-3/4	16-3/4	18-3/4
Pressure	5,000	10,000	10,000	5,000	10,000	10,000	10,000	10,000
Over-all length (inches)	129.25	139	156.375	118.375	127.25	129.375	132.5	138.25
Over-all height flanged(in	43.062	49.688	--	43.5	55.875	60.25	44.875	54.25
Over-all height hub (in)	34.938	41.938	43.234	37.75	49.5	51.934	37.625	43.125
Over-all width (inches)	35.75	39.5	42.5	46.5	55.125	56.875	57.375	59.625
Centerline lower outlet to lower flange (inches)	14.812	19.375	--	15.375	21.313	23.5	13.75	18.875
Centerline lower outlet to lower hub (inches)	10.75	15.5	13.875	12.5	--	19.375	10.125	13.313
Top of upper ram to top flange (inches)	16.906	20.219	--	19	23.934	26.406	17.688	22.125
Top of upper ram to top hub (inches)	12.844	16.344	15.344	16.125	20.75	22.25	14.063	16.563
Ram height (inches)	9.25	9.25	12	5.5	8	8	9.5	10
Centerline of preventer to outlet flange (inches)	--	--	--	28.313	33.375	34.25	29.5	33.375
Weight (pounds)	13,750	23,300	28,900	9,475	19,870	20,400	21,000	28,500

Table 3.3 - Listing of Dimension and Working Pressures by Manufacturer for Double Ram-type Preventers

	CAMERON IRON WORKS[10]			N L RIG EQUIPMENT[11]			HYDRIL[12]	
Size	16-3/4	16-3/4	18-3/4	16-3/4	16-3/4	18-3/4	16-3/4	18-3/4
Pressure	5,000	10,000	10,000	5,000	10,000	10,000	10,000	10,000
Over-all length (inches)	129.25	139	156.375	118.375	127.25	129.375	132.5	138.25
Over-all height flanged(in)	68.875	77.75	--	61.375	74.125	78.063	73	85.75
Over-all height Hub (in)	60.75	70.0	73.812	55.625	65.75	69.75	65.75	74.625
Over-all width (inches)	35.75	39.5	42.5	46.5	55.125	56.875	57.375	59.625
Centerline lower outlet to lower flange (inches)	14.812	19.375	--	15.375	20.813	22.781	13.75	18.875
Centerline lower outlet to lower hub (inches)	10.75	15.5	13.875	12.5	17.625	18.625	10.125	13.313
Top of upper ram to top flange(inches)	16.906	20.219	--	19	23.934	26.406	17.687	22.125
Top of upper ram to top hub(inches)	12.844	16.344	15.344	16.125	20.75	21.25	14.063	19.563
Ram height (inches)	9.25	9.25	12	5.5	8	8	9.5	10
Centerline upper outlet to lower flange (inches)	40.625	47.438	--	33.25	40.25	42.25	41.875	50.375
Centerline upper outlet to lower hub (inches)	36.562	43.562	44.875	30.375	36.875	37.875	38.25	44.813
Top of lower ram to bottom of upper ram (inches)	16.562	18.812	19.125	12.375	11.25	11.25	23.625	21.5
Centerline of preventer to outlet flange (inches)	--	--	--	28.313	33.375	34.25	29.5	33.375
Weight (pounds)	26,940	43,500	56,950	16,200	30,400	35,060	43,000	52,000

pressure does not affect operation.

The annular-type preventer employs a ring of reinforced synthetic rubber as a packing unit that surrounds the wellbore to effect a shutoff. Annular preventers can effect pressure shutoff on any object of any shape or diameter that might be in the hole. Thus an annular BOP can be closed on the drill string the moment a kick is detected, irrespective of the position of a tool joint relative to the BOP stack. Once the annular BOP is closed on the drill string, the operator can raise or lower the pipe until the tool joint is clear of the stack, after which the proper ram-type preventer may be closed. The annular BOP can be used for continuous stripping. Since tool joints will pass through the closed annular BOP without damage to the packer, continuous stripping either into or out of the hole is possible. Stripping into the hole is often necessary when a kick occurs, since it is necessary to get the pipe back down to the bottom of the hole for total circulation. Continuous stripping represents a substantial saving of rig time as compared to the "hand over hand" stripping that is necessary when stripping through closed rams. Of the rigs surveyed, five were equipped with Shaffer annular preventers while three rigs contained Hydril preventers.

3.1.4 A Lower Marine Riser Connector

A low-pressure connector on the top of the BOP stack connects the marine riser to the BOP stack. The lower marine riser assembly rotates to align and connect the hydraulic lines as well as choke and kill line subs. The BOP stack remains stationary as the lower riser assembly is rotated until the locking pin engages the slot in the receiver plate or the BOP stack. When the pin is engaged, the retractable connectors in the lower marine riser stab plate are aligned with the receptacle openings of the BOP receiver plate. Hydraulic pressure applied to the receptacle connectors extend the connectors into the receptacle openings. Cameron Iron Works is one company which provides for this type of connector.

Figure 3.5 is the Zapata Concord's blowout preventer stack assembly. This stack is a 10,000 psi, 18-1/4 inch BOP assembly composed of two Cameron type U double ram preventers, and two N L Rig spherical preventers. The number 1 pipe ram is a shear/blind ram. The number 2 and 4 rams are 5 inch pipe rams, and the number 3 ram is a 3-1/2 inch pipe ram. Note that the second spherical preventer is actually attached to the lower marine riser package. This is a typical subsea blowout preventer stack arrangement for the deep water floaters.

3.2 The Control System

The control system is a means to operate and control the equipment on the BOP stack from the surface location by electrically, hydraulically, or acoustically opening and closing the various preventers. The control system must also handle the choke and kill line valves as well as pro-

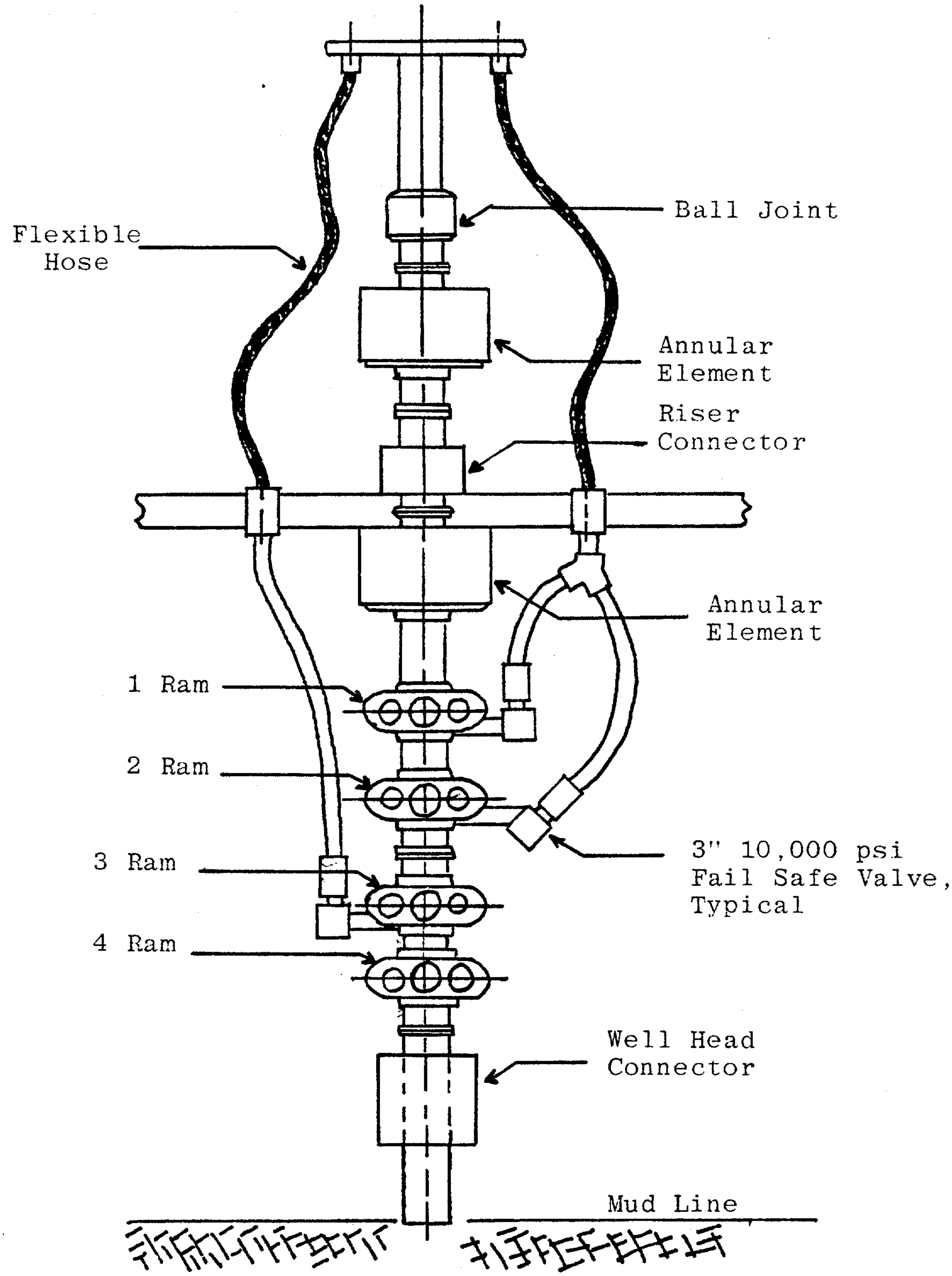

Figure 3.5 -Zapata Concord's Blowout Preventer Stack Assembly.

vide a means to connect and disconnect the BOP stack. The control system plays an important role in any well control operation. The rapid closure of the preventers is essential, not only to minimize entry of fluid into the wellbore, but also to lessen the damage to the rams and packing units due to mud abrasion. The control system is composed of surface equipment, subsea hose reels, and subsea remotely controlled pods. The surface equipment includes accumulator banks, power supplies, and various control panels. The subsea hose reels provide storage for the hydraulic hoses and/or electric cables which provide communication between the surface equipment and subsea control pods. The subsea control pods receive signals from the surface control panels and perform the actual opening and closing of the BOP stack preventers and valves.

The surface components include accumulators of sufficient capacity to close all the units in the BOP assembly at least once with a reasonable reserve of fluid and pressure. In addition to the surface accumulators, subsea accumulators are placed on the BOP stack. Because of their proximity to the control pods, the subsea accumulators provide high pressure and high flow rates for faster operation of the stack functions.

Two systems have been developed for remote control of the stack equipment.[13] The first is a completely hydraulic control system. The control hoses are stored on powered reels on the floating rig and are attached to a separate wireline cable as they are lowered to the subsea BOP stack. The opening and closing of the preventers and valves on the BOP stack are accomplished by sending hydraulic signals from the surface control panel down through the hydraulic hose lines to the subsea control pods. Hydraulic pressure is then directed tp the appropriate preventer or valve on the BOP stack. The pressure drop through the long hydraulic lines may become so great that the closing time becomes difficult.

In the second system, the surface control panel transmits electrical commands to the subsea BOP control pod through an electrical cable. The subsea electrical components receive these commands and convert them into hydraulic signals for operation of the BOP stack components. This type of system is called and electro-hydraulic system and boasts of a quicker surface to BOP stack response time. Both the totally hydraulic and the electro-hydraulic control systems are equipped with two pods and control cables to have 100 percent standby capacity in case of failure of one pod. Each pod is completely independent of the other.

In addition to the hydraulic and electro-hydraulic systems that are employed in the control system, an acoustic system is also available in which a transducer is mounted on the hull of the drillship or floating rig. This transducer sends signals to a receiving transducer located on the subsea stack. The subsea unit then actuates the appropriate solenoid valves, which control the stack preventers and valves. The subsea unit can then transmit signals back to the surface unit confirming that the desired action is completed. This system is now being employed strictly as a backup to the previously described control systems.

Of the rigs surveyed, most are equipped with the electro-hydraulic control system. The remaining rigs are equipped with the totally hydraulic system. The majority of the rigs surveyed do have an acoustic backup system.

API Recommended Practice No. 53[9] suggests as a minimum requirement, closing units for subsea installations should be equipped with accumulator bottles with sufficient volumetric capacity to provide the usable fluid volume* (with pumps inoperative) to open and close the ram preventers and one annular preventer and retain a 50 percent reserve.

The accumulator pumps and closing manifold should be located at a safe distance from the well. An alternate control panel should be located on the rig floor or at another location convenient to the driller. Alternate means of producing hydraulic pressure should be provided in case the main system fails. The usual hydraulic-power-arrangement is to provide electrically driven pumps, with standby air-powered pumps plus stored compressed air.

API Recommended Practice No. 53[9] suggests that a flow

* Usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the accumulator operating pressure and 200 psi above the precharge pressure.

meter be included in the surface control system in which the volume of fluid going to a particular function will indicate if that function is operating properly.

API Recommended Practice No. 53[9] suggests the combination of air and electric pumps should be capable of charging the entire accumulator system from precharge to the maximum rated charge pressure in fifteen minutes or less. The pumps should be installed so that when the accumulator pressure drops to 90 percent of the preset level, a pressure switch is triggered and the pumps are automatically turned on.

3.3 Marine Riser Systems

A marine riser system is used to provide a return flow path from the wellbore to the floating drilling vessel and to guide the drill string and tools to the wellhead on the ocean floor. Components of this system include remotely operated connectors, flexible (ball) joints, riser sections, telescopic joints, and tensioners. The marine riser system should have adequate strength to withstand:

1. dynamic loads while running and pulling the blowout preventer stack;
2. lateral forces from current and acceptable vessel displacement;
3. cyclic forces from waves and vessel movement;
4. axial loads from the riser weight, drilling fluid weight, and any free standing pipe within the riser;

5. axial tension from the riser tensioning system at the surface or from buoyancy modules attached to the exterior of the riser.

Internal pressure rating of the marine riser system, ie, pipe, connectors, and flexible joint, should be at least equal to the rated working pressure of the diverter system plus the maximum difference in hydrostatic pressures of the drilling fluid and sea water at the ocean floor.

A remotely operated connector (hydraulically actuated) connects the riser pipe to the blowout preventer stack and can also be used as an emergency disconnect from the preventer stack should conditions warrant. Connector internal diameter should be at least equal to the internal bore of the blowout preventer stack. Its pressure rating can be equal to either the other components of the riser system or to the rated working pressure of the blowout preventer stack. On most of the rigs, an annular preventer is included in the lower riser package, thus the hydraulic connector should have a pressure rating conforming to the preventers in the stack.

A flexible joint (ball joint) is used in the marine riser system to minimize bending movements, stress concentrations, and problems of misaligned engagement. The angular freedom of a flexible joint is normally 10 degrees from vertical. The flexible joint is always installed at the bottom of the riser system immediately above the annular preventer.

Riser pipe size is determined by the bore of the blowout preventer stack and wellhead, with allowance for clearance in running drilling assemblies, casing, and hangers. For 16-3/4 inch BOP stack, an 18-5/8 inch O.D. riser pipe is used. An 18-3/4 inch BOP stack employs a 21 inch O.D. riser, usually with 1/2 inch wall thickness. Riser pipe joints are normally made to standard lengths of 50 feet. Pipe joints 5, 10, 15, and 25 feet long are employed to obtain assemblies shorter than even encrements of the 50 foot lengths.

Marine riser connectors are designed to minimize installation time of the riser system. The riser connectors must be able to support the weight of the BOP stack as it is lowered and landed on the wellhead. The integral marine riser, the standard arrangement at this time, has the choke and kill lines installed on the riser joints so that they are simultaneously stabbed and made up when the riser connector is made up. This eliminates the handling, rigging, and running time that was necessary with older types of systems. The choke and kill lines can be tested while being run to ensure that they are pressure tight using the integral riser system. The choke and kill lines on the marine riser terminate at the telescopic joint just below the vessel hull. Flexible lines extend from the telescopic joint to the drilling vessel where connections are made to lines leading to the choke and kill manifold. The choke and kill lines on the rigs surveyed are pressure rated at

10,000 psi. The choke and kill lines are normally 3 inch O. D..

The telescopic, or slip joint is used at the top of the marine riser and functions as follows:

1. It compensates for vertical movement (heave) of the vessel while drilling.
2. It provides a means of connecting a bell nipple or diverter assembly to the riser.
3. It provides fittings for choke and kill line hoses to the drilling vessel.
4. It provides attachment for the riser tensioner system.

A telescopic joint (Figure 3.6) is comprised of an outer barrel attached to the marine riser assembly and an inner barrel attached to the drilling vessel. The bell-nipple or diverter assembly is attached to the inner barrel which in turn is suspended from the rotary beams of the rig. The outer barrel is connected to the top joint of the marine riser and has connections for attachment of the riser-tensioning lines. The stroke length of the inner barrel inside the outer barrel is usually on the order of 40 to 50 feet.

The outer barrel of the telescopic joint is connected to the riser pipe and remains fixed with respect to the ocean floor. It is suspended from the floating vessel by means of the tensioning system. It provides connections for the kill and choke lines.

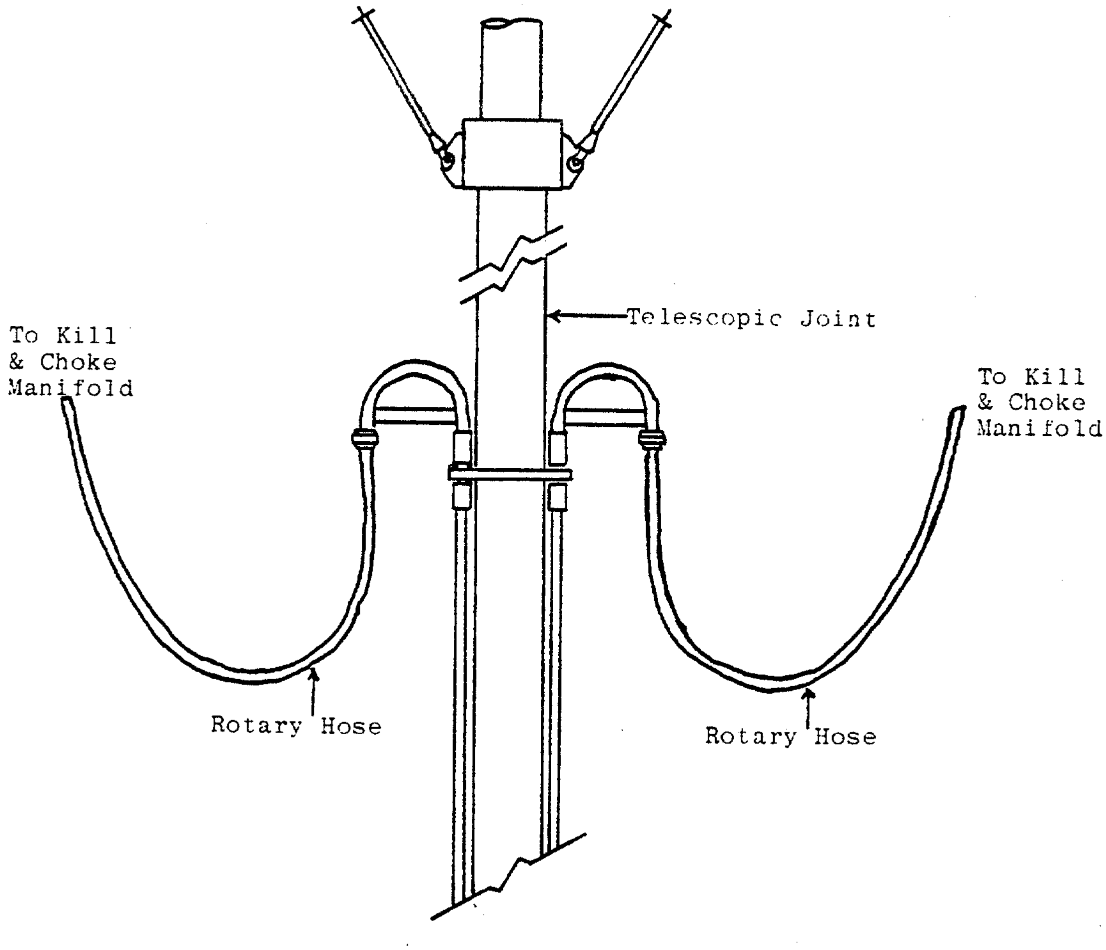

Figure 3.6 - Telescopic joint showing flexible connections at the top of the marine riser for choke and kill lines

The inner barrel is attached to and moves with the drilling vessel. It has an internal diameter that makes it compatible with other parts of the riser system. The top of the inner barrel is attached to the bell-nipple, or diverter system, and to the mud-return circulating system of the rig.

The major suppliers of marine riser systems are Cameron Iron Works, National Supply Company, Regan Offshore, and Vetco Offshore.

3.4 The Diverter System

A diverter system is a means of controlling well flows encountered at relatively shallow depths by directing the flow away from the rig. A diverter system gives a degree of protection prior to setting the casing string on which the blowout preventer stack is installed. It is designed to pack off around the kelly or drill string and direct flow safely away from the drill vessel. Valves in the system direct the well flow through piping on the vessel so that gas vented downwind (Figure 3.7).

When a diverter system is used, there must be a short string of casing or drive pipe installed below the mudline. A marine riser is attached to this casing, and the diverter system is connected to the inner barrel of the telescopic joint and secured to the rig substructure.

Vent lines from the diverter usually have large diameters (10 inches or more) and are designed to divert well

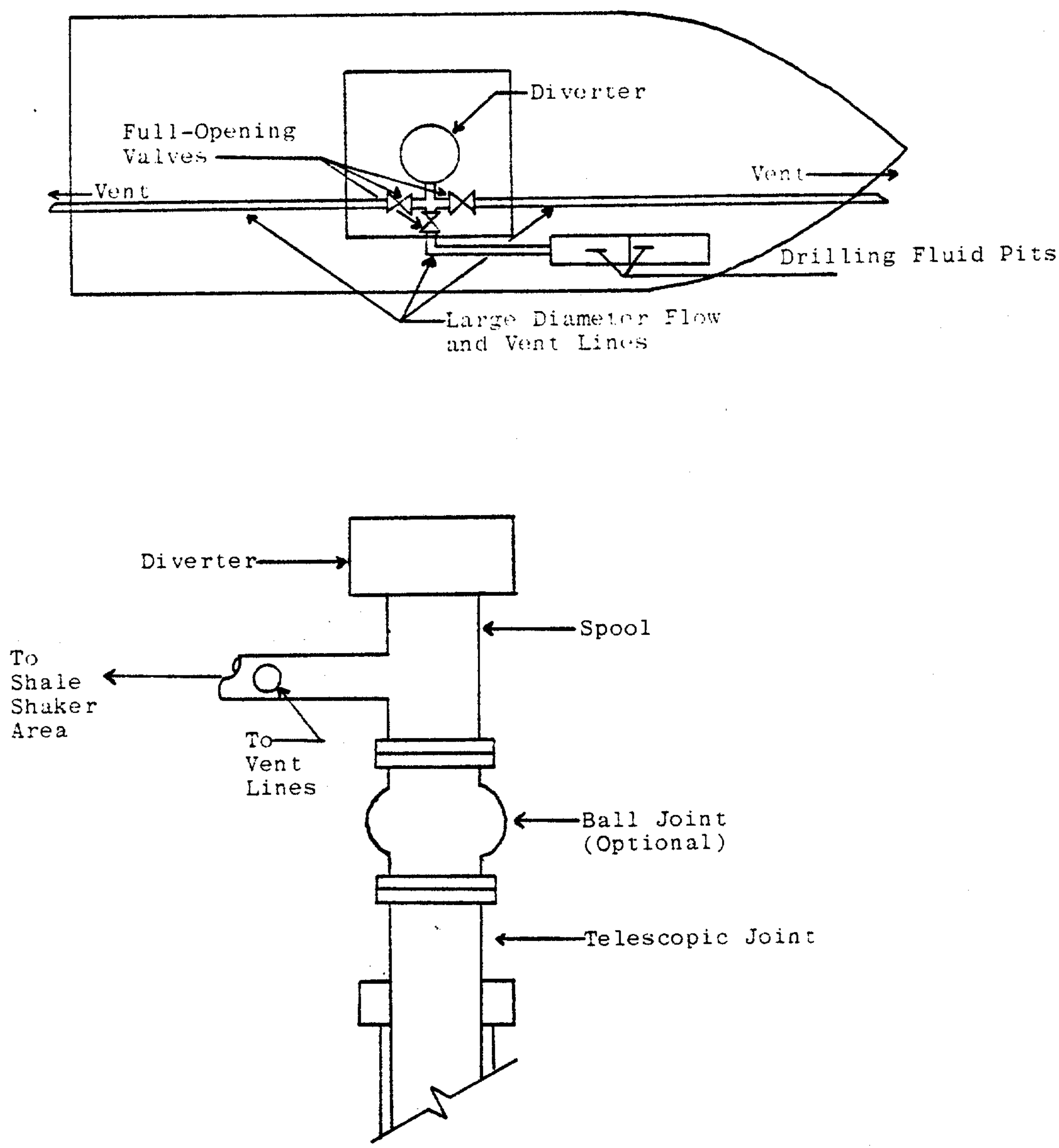

Figure 3.7 - Typical Diverter System for Subsea Installation

fluids with a minimum of back pressure on the well. They are directed to opposite extremities of the vessel. All valves in the diverter line are full opening and designed to automatically open whenever the diverter is closed.

High pressure on the diverter is not practical because the telescopic joint pack off seal is not useful for pressure exceeding 50 to 100 psi. Excessive pressure on the diverter could cause formation rupture and cratering around the conductor casing and create a very hazardous condition for the floating rig.

Most of the functions of the diverter system are hydraulically operated from the diverter control panel. Once the diverter is closed on the drill string, the flow line on the shale shaker is automatically closed and the port or starboard line valve is opened depending on wind direction.

Both Regan Offshore and Vetco Offshore offer diverter systems which can be run through 37-1/4 inch or 49-1/2 inch rotary tables and land in the housing built into the rotary table beams.

3.5 The Choke and Kill Manifolds

If the hydrostatic head of the drilling fluid is insufficient to control subsurface pressure, formation fluids will flow into the well. To maintain well control, back pressure is applied by routing mud returns through adjustable chokes until the well flow condition is corrected. The chokes are connected to the blowout preventer stack through an arrangement of valves, fittings, and lines which provide alternative return flow routes or permit the flow to be halted entirely. This equipment assemblage is designated the "choke manifold". Figure 3.8 illustrates a typical choke and kill manifold assembly for a subsea installation with facilities adequate for 10,000 psi rated working pressure.[9] On subsea installations, choke and kill lines are manifolded to permit pumping through either line. Other features are remotely controlled adjustable chokes, duplicate adjustable choke systems (manual) to permit control through either the choke or kill line, double valves immediately upstream of each choke, an accurate pressure gauge, and tie-ins to both drilling fluid and high pressure pump systems.

The API Recommended Practice No. 53[9] for planning and installation of choke manifolds for subsea installations include:

1. the assembly, connections, full-opening valves, fittings, piping, etc., subject to well or pump pressure should be flanged, clamped, or welded and have a rated working pressure at least equal to the rated working pressure of the blowout preventers.
2. all components should be selected in accordance with applicable API Specifications, taking into consideration pressures, volumes, temperatures, and conditions under which they may be operated.
3. the assembly should be 3 inch nominal diameter or

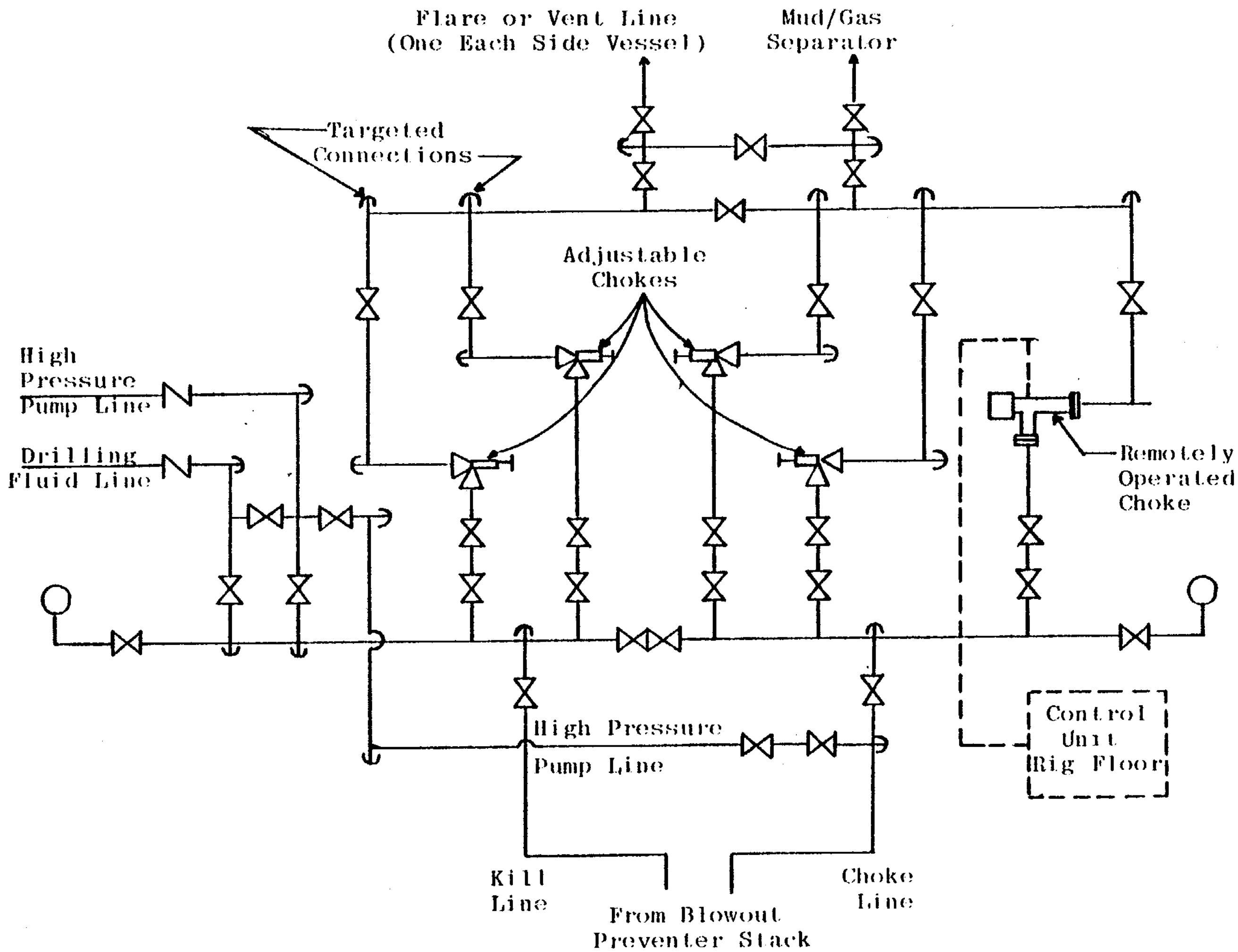

Figure 3.8 - Typical Choke Manifold Assembly for Subsea Installation[9]

larger, have a minimum number of turns, and be securely anchored. Turns in the assembly should be targeted.

4. the choke control station, whether at the manifold or remote from the rig floor, should be as convenient as possible and should include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, pump strokes, etc., greatly increases well control efficiency.

5. rig air systems should be checked to assure their adequacy to provide the necessary pressure and volume requirements for controls and chokes. A redundant automatic choke control system should be provided in the event that air becomes unavailable.

6. itital testing of the entire choke manifold assembly to the rated working pressure of the preventers should be performed when the blowout preventer stack is on the test pump, and thereafter whenever the blowout preventers are tested.

7. lines downstream of the choke manifold are normally not required to contain rated manifold working pressure, but should be tested during the initial installation.

8. lines downstream of the choke manifold should be securely anchored, be of sufficient size to minimize friction, and permit flow direction either to a mud/ gas separator, ventlines, or to production facilities

or emergency storage. Two vent lines diametrically opposite one another are required to compensate for variations in wind direction.

Choke and kill manifolds are permanently installed at the time of rig construction. However all of the rigs surveyed utilized the recommended configuration of the API.

3.6 Government Regulations

This report addresses only those rigs capable of drilling in 2,000 feet of water or greater. Consequently the only government regulatory body that is responsible for drilling in this water depth is the U. S. Geological Survey. When a lease is issued by the Department of Interior to a individual operator, the operator is required to abide by any rules, regulations, or OCS Orders issued in accordance with the Outer Continental Shelf Lands Act[14]. OCS Order No. 2[6] was issued by the U.S.G.S. to govern drilling operations on the Outer Continental Shelf. Among other things Order No. 2[6] sets guidelines for BOP equipment and well control standards which must be met while drilling on the OCS.

Section 5 of Order No. 2[6] deals with Blowout Preventer equipment requirements. It sets minimum requirements for any blowout preventer system, such as:

1. A hydraulic actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with

a minimum pressure of 1,400 kPa (203 psi) above the precharge pressure. An accumulator backup system, supplied by a secondary power source independent from the primary power source, shall be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices shall be provided on the ram-type preventers. The method of BOP actuation control, such as hydraulic, acoustic, or other methods, shall be described and included in the Application for Permit to Drill.

2. At least one operable remote blowout-preventer-control station, in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

3. A drilling spool with side outlets, if side outlets are not provided in the BOP body, to provide for separate kill and choke lines.

4. A kill line equipped with 2 kill-line valves is required. The master valve shall be located adjacent to the BOP. This valve shall not normally be used for opening or closing on flowing fluid. The second valve shall be located adjacent to the master valve. The valve shall be used as the control valve.

5. A fill-up line above the uppermost preventer.

6. A choke manifold equipped in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems," API RP 53[9], First Edition, February 1976

reissued February 1978, Sections 3A and 3B, or subsequent revisions which the Chief, Conservation Division, has approved for use.

7. Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold shall have a pressure rating at least equal to the anticipated surface pressure.

8. A wellhead assembly with a working pressure at least equal to the anticipated surface pressure.

In addition, Section 5.2 of OCS Order No.2[6] sets minimum requirements for drilling below the casing strings for subsea blowout preventer stacks as follows:

<u>Drive or Structural</u>

1 - Annular

1 - Diverter System - Diverter systems installed prior to the effective date of this Order shall include a minimum of two 10-centimeter (4-inch) internal diameter lines and full-opening valves. Diverter systems installed or modified after the effective date of this Order shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves. The flow path from the BOP to the branch point of diverter lines in new systems shall have a minimum internal diameter of 15-centimeters (6-inches).

<u>Conductor</u>

1 - Annular

1 - Diverter System - Diverter systems installed prior to the effective date of this Order shall include a minimum of two 10-centimeter (4-inch) internal diameter lines and full-opening valves. Diverter systems installed or modified after the effective date of this Order shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves. The flow path from the BOP to the branch point of diverter lines in new systems shall have a minimum internal diameter of 15-centimeters (6-inches).

Surface

1 - Annular

1 - Blind Shear Ram

2 - Pipe Rams

Intermediate

1 - Annular

1 - Blind Shear Ram

2 - Pipe Rams - When a tapered drill string is in use, the BOP stack shall be equipped with two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe.

The following sections of OCS Order No. 2[6] set minimum testing requirements.

5.7.1 BOP Testing Frequency. Surface and subsea BOP stacks shall be tested as follows:

a. When installed.

b. Before drilling out after each string of casing has been set.

c. At least once each week, but not exceeding 7 days between tests, alternating between control stations. A period of more than 7 days between blowout-preventer tests is allowed when well operations prevent testing and remedial efforts are being performed, provided the tests will be conducted as soon as possible before normal operations resume, and the reason for postponing testing is entered into the log. Well operations which prevent testing are stuck drill pipe and pressure control operations. Testing shall be at staggered intervals to allow each drilling crew to operate the equipment.

d. Following repairs that require disconnecting a pressure seal in the assembly.

5.7.3 Pressure Testing Subsea BOP Systems. Subsea BOPs and all related well-control equipment shall be tested at the surface with water to the anticipated surface pressure, except that the annular-type BOP shall not be tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the seafloor, the control equipment and pipe rams, conforming to the drill string within the stack, shall be tested at the anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. The annular-type BOP shall be tested at 70 percent of its rated working pressure or 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. Before drilling out of each casing or liner shoe, the blind rams shall be tested as required for pipe rams. After drilling out of each casing or liner shoe, the blind rams need not be tested until before drilling out the subsequent casing or liner shoe.

5.7.5 Actuation of Subsea BOP Systems. The actuation frequency requirements for subsea BOP systems shall be:

a. Pipe rams shall be actuated every other day. In order to prevent damage to the rams, complete closure of the rams on the drill pipe is not required, provided movement of the rams is indicated by the hydraulic system pressure and flow indicators.

b. The blind shear rams shall be actuated once each trip from alternate control stations and control systems; however, not more than once each day if multiple trips are made. During the weekly pressure tests, all hydraulic systems except those actuating the blind shear rams shall be actuated from each control station and control system.

c. Annular-Type Preventer - Once each week in conjunction with the pressure test.

d. Control Stations - Once each trip from alternate control stations, while the drill pipe is out of the hole; however, not more than once each day if multiple trips are made. If either system is not functional, further drilling operations shall be suspended until that system becomes operable.

e. Choke manifold valves, kelly cocks, drill pipe safty valves - Weekly.

Section 5.8 sets inspection and maintenance requirements.

Section 5.9 mandates blowout-preventer drills.

Section 7 of OCS Order No. 2[6] sets training standards which will be discussed in the chapter on procedures.

CHAPTER IV

CURRENT WELL CONTROL PROCEDURES

The primary method of controlling formation pressures is accomplished by the weight of the circulating fluid in the hole. In the event that this does not prove adequate, the hole will be protected by actuating the blowout preventer equipment. This will prevent further intrusion of the formation fluids into the hole. In this static state, the proper mud weight can then be calculated. By opening the choke and kill lines, the formation fluids can then be circulated out of the borehole. Three methods for circulating out a "kick" from the borehole have been developed. Basically they all have the same general principle of keeping the bottom hole pressure constant at a value slightly above the formation pressure while pumping out the kick.

4.1 Government Regulations

It is critical that the drilling personnel aboard a rig can recognize the indications that a kick is occurring, determine that formation fluids have entered the borehole, and if so can safely and swiftly circulate the formation fluids from the wellbore. The U.S. Government is requiring drilling personnel to attend classroom lectures and hands-on demonstrations to qualify to drill on offshore locations. Under U.S.G.S. OCS Order No. 2[6], paragraph 7.3, all drillers, toolpushers, and operator's representatives should receive training in well-control operations. In order to maintain qualifications, drillers, toolpushers, and operator's representatives should successfully complete a refresher course annually and repeat the basic well-control course every 4-years. The refresher course should be completed within 45 days of the students anniversary date. Records should be maintained at the drill site for the affected personnel, indicating the specific training and refresher courses successfully completed, the dates of completion, and the names and dates of the courses.

4.2 Approved Well Control Training

Both the basic training course and the refresher course must be approved by the U.S.G.S.. The U.S. Geological Survey has issued "Outer Continental Shelf Standard Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations"[15] (GSS-OCS-Ti). This publication presents guidelines for course curricula. This includes course curricula for the rotary helper, the derrickman, the driller, the toolpusher, and operator representative. Topics such as the blowout-prevention equipment, warning signs of kicks, drilling fluids, properly shutting in a well for well control purposes, well control operations, and relevant government regulations are outlined. The American Petroleum Institute has published similar training and qualifications guidelines in their Recommended Practice API RPT-3.[16] Both these publications recommend qualification procedures. This includes prerequisites, the type of test, and documentation of test results. The rotary helper and derrickman are required to participate in a crew performance drill in which they are to carry out their assignments within the time limit prescribed for the drill. The drill, toolpusher, and operator's representative are required to take a written and/or verbal test as well as a hands-on demonstration of his understanding of the well-control equipment, techniques, and principles outlined in his course curricula.

A U.S.G.S. representative will visit the training site to discuss with course lecturers their curricula and qualifications. He will review the course manuals and outline to see if they comply with the "Outer Continental Shelf Standard Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations".[15] He may elect to participate in an actual course before recommending that the course receive U.S.G.S. approval. To date, 55 schools have received U.S. G.S. approval for rotary helpers and derrickmen; and 42 schools have been approved by the U.S.G.S. as basic training courses for the driller, toolpusher, and operator representative. Forty-one of these schools have been approved by the U.S.G.S. for refresher courses for the driller, toolpusher, and operator representative. Both the basic training and refresher courses cover the case of drilling from a bottom supported vessel as well as drilling from a floating vessel. Tables 4.1 thru 4.3 list these U.S.G.S. approved training courses.

4.3 Well Shut-in Procedures

Of the 42 approved basic training courses, 11 are conducted by oil company personnel for in-house training of their workers. These courses were of special interest in this study, since in all cases, it is the operator's prerogative to elect the method of well control he will utilize during the drilling of a well. The U.S.G.S. was contacted to provide the well control manuals for these 11 courses. However, due to the large volume of material requested, only four of these training manuals were received. The U.S.G.S. stated that these 4 manuals would provide a representative sample of the course curricula and procedures recommended by these courses. The manuals received are from the courses approved for Exxon Corporation, Cities Service Company, Gulf Research and Development, and Shell Oil Company.

The shut-in procedures outlined in all four manuals were identical. Once formation flow into the wellbore is suspected, the following procedures are recommended:

1. Stop the rotary.

Table 4.1 - U.S.G.S. Approved Schools for Rotary Helper and Derrickmen

USGS Approved Well-Control Schools

Rotary Helper and Derrickmen

Diamond M. Company
Dixilyn-Field Drilling Company
Global Marine Drilling Company
Huthnance Drilling Company
Marine Drilling Company
Prentice and Records Enterprises, Inc.
Reading and Bates Drilling Company
Rowan Companies, Inc.
Salen Offshore Drilling Company
Shell Oil Company
Teledyne Movible Offshore, Inc.
Transworld Drilling Company
Zapata Offshore Company
Marlin Drilling Company, Inc.
Progress Drilling & Marine, Inc.
Dolphin International, Inc.
The Offshore Company
Western Oceanic, Inc.
Chiles Drilling Company
Penrod Drilling Company
Scan Drilling Co.(U.S.A.) Inc.
Noble Drilling Co.
Houston Offshore International, Inc.
O & U Drilling, Inc.
Services, Equipment & Engineering
Atwood Oceanics, Inc.
Atwood Group, Inc.
MUDTECH

Nicklos Drilling Company
Keydril Company
Phoenix Management Corperation
Bokenkamp Drilling Company, Inc.
Peter Bawden Drilling Inc.
Temple Drilling Company
Mayronne Company
Ocean Drilling & Exploration Company
Keyes Offshore, Inc.
Pool Offshore Company
Challenger Drilling Inc.
Dual Offshore Company
Sea Drilling Corporation
Cactus International, Inc.
Atlantic Pacific Marine Corporation
Booker Drilling Company, Inc.
Broughton Drilling Company
Loffland Brothers Company
Cyclops Drilling Company
Circle Bar Drilling Company
Flour Drilling Services, Inc.
Dan-Tex International Inc.
Maurer Engineering Inc.
Moran Drilling Corp.
J.F.P. Drilling Company, Inc.
Griffen-Alexander Drilling Co.
Goldrus Drilling Company, Inc.

Table 4.2 - U.S.G.S. Approved Basic Courses for Drillers, Toolpushers, and Operator Representatives. (surface and subsea installations)

Chevron U.S.A. Inc.	OR	SUR, SS
Conoco Inc.	OR	SUR, SS
Delta Drilling Company	DR, TP, OR	SUR, SS
Dresser Industries	DR, TP, OR	SUR, SS
EXXON	DR, TP, OR	SUR, SS
IMCO Services	DR, TP, OR	SUR, SS
Louisiana State University	DR, TP, OR	SUR, SS
Milchem Incorporated	DR, TP, OR	SUR, SS
Pool Offshore Company	DR, TP, OR	SUR
Reading and Bates Drilling Company	DR, TP, OR	SUR
Shell Oil Company	DR, TP, OR	SUR, SS
Texaco	DR, TP, OR	SUR, SS
University of Southwestern Louisiana	DR, TP, OR	SUR, SS
Ventura College	DR, TP, OR	SUR, SS
Petroleum Training and Technical Services	DR, TP, OR	SUR, SS
Murchison Drilling Schools	DR, TP, OR	SUR, SS
Ocean Drilling and Exploration Co.	DR, TP, OR	SUR, SS
Diamond M. Company	DR, TP, OR	SUR, SS
Cities Service Company	OR	SUR, SS
Shell Oil Company (White Castle)	DR, TP, OR	SUR, SS
University of Oklahoma	DR, TP, OR	SUR, SS
NL Petroleum Services	DR, TP, OR	SUR, SS
University of Texas at Austin (PETEX)	DR, TP, OR	SUR, SS
Gulf Research and Development	DR, TP, OR	SUR, SS
Rike Service Inc.	DR, TP, OR	SUR, SS
Prentice and Records Enterprises, Inc.	DR, TP, OR	SUR, SS

Table 4.2 - (continued)
U.S.G.S. Approved Basic Courses for Drillers, Toolpushers, and Operator Representatives. (surface and subsea installations)

Amoco Production Company	OR	SUR, SS
Loffland Brothers Company	DR, TP, OR	SUR, SS
Atlantic Pacific Marine Corp.	DR, TP, OR	SUR, SS
Basic Research and Training, Inc.	DR, TP, OR	SUR, SS
Well Control School, Inc.	DR, TP, OR	SUR, SS
Alaska Skill Center	DR, TP, OR	SUR, SS
Keydril Company	DR, TP, OR	SUR, SS
Arco Oil & Gas Company	TP, OR	SUR, SS
Marlin Drilling Company, Inc.	DR, TP, OR	SUR, SS
Parker Drilling Company	DR, TP	SUR
Oklahoma Petroleum Training Corp.	DR, TP, OR	SUR, SS
Union Oil Company of California	DR, TP, OR	SUR, SS
Cape Cod Community College	DR, TP, OR	SUR, SS
Western Oceanic, Inc.	DR, TP, OR	SUR, SS
Dixilyn-Field Drilling Company	DR, TP, OR	SUR, SS
Preston L. Moore Inc.	TP, OR	SUR

Table 4.3 - U.S.G.S. Approved Refresher Courses for Drillers, Toolpushers, and Operator Representatives. (surface and subsea installations)

Chevron U.S.A. Inc.	OR	SUR, SS
Conoco Inc.	OR	SUR, SS
Delta Drilling Company	DR, TP, OR	SUR, SS
Dresser Industries	DR, TP, OR	SUR, SS
IMCO Services	DR, TP, OR	SUR, SS
Louisiana State University	DR, TP, OR	SUR, SS
Milchem Incorporated	DR, TP, OR	SUR, SS
Pool Offshore Company	DR, TP, OR	SUR
Reading and Bates Drilling Co.	DR, TP, OR	SUR
Shell Oil Company	DR, TP, OR	SUR, SS
Texaco	DR, TP, OR	SUR, SS
University of Southwestern Louisiana	DR, TP, OR	SUR, SS
Ventura College	DR, TP, OR	SUR, SS
Petroleum Training and Technical Services	DR, TP, OR	SUR, SS
Murchison Drilling Company	DR, TP, OR	SUR, SS
ODECO	DR, TP, OR	SUR, SS
Diamond M. Company	DR, TP, OR	SUR, SS
Cities Service Company	OR	SUR, SS
Shell Oil Company (White Castle)	DR, TP, OR	SUR, SS
University of Oklahoma	DR, TP, OR	SUR, SS
NL Petroleum Services	DR, TP, OR	SUR, SS
University of Texas at Austin(PETEX)	DR, TP, OR	SUR, SS
Rike Service Inc.	DR, TP, OR	SUR, SS
Prentice and Records Enterprises, Inc.	DR, TP, OR	SUR, SS
Amoco Production Company	OR	SUR, SS

Table 4.3 - (continued)
U.S.G.S. Approved Refresher Courses for Drillers, Toolpushers, and Operator Representatives. (surface and subsea installations)

Loffland Brothers Company	DR, TP, OR	SUR, SS
Atlantic Pacific Marine Corp.	DR, TP, OR	SUR, SS
Basic Research and Training, Inc.	DR, TP, OR	SUR, SS
Well Control School, Inc.	DR, TP, OR	SUR, SS
Alaska Skill Center	DR, TP, OR	SUR, SS
Keydril Company	DR. TP, OR	SUR, SS
Arco Oil and Gas Company	TP, OR	SUR, SS
Marlin Drilling Company, Inc.	DR, TP, OR	SUR, SS
Oklahoma Petroleum Training Corp.	DR, TP, OR	SUR, SS
Union Oil Company of California	DR, TP, OR	SUR, SS
Cape Cod Community College	DR, TP, OR	SUR, SS
Western Oceanic, Inc.	DR, TP, OR	SUR, SS
Dixilyn-Field Drilling Company	DR, TP, OR	SUR, SS
Parker Drilling Company	DR, TP, OR	SUR
Preston L. Moore Inc.	TP, OR	SUR
Gulf Research and Development	DR, TP, OR	SUR, SS

2. Pick up kelly to previously calculated space out elevation.
3. Shut down the mud pumps.
4. Check for flow.
5. If flowing, notify superintendent and tool-pusher.
6. Open the subsea choke valve on BOP control panel.
7. Close the annular preventer.
8. Close the adjustable choke.
9. Record the drill pipe and casing pressures.
10. Record the pit gain.
11. Adjust the closing pressure on the annular BOP.
12. Initiate hang-off procedure.
13. Re-evaluate the shut-in pressures.
14. Initiate kill procedures.

The above procedure is for a kick, taken while drilling. All of these operators recommended the "wait-and-weight" method for kill procedure, stating that this method will produce the lowest pressures at the casing seat. The U.S.G.S. personnel responsible for approving training courses courses confirmed this is the most commonly recommended well control method.

4.4 Pump Start-up Procedures

All the company well control manuals review the 3 well control methods ie, the "Drillers Method", the "Wait-and-

Weight Method", and the "Circulate-and-Weight Method". All of these manuals suggest using the "Wait-and-Weight Method" for floating drilling vessels. The pump start-up procedures are identical to those employed for surface BOP operations. A reduced circulating pressure must be predetermined by circulating thru the choke line at selected kill pump speeds. When the kill speed has been determined, the drill pipe and casing pressures recorded, and the kill mud weight established, the pump is started up by holding the casing pressures constant until the desired kill speed has been established.

4.5 Pump-out Procedures

The drill pipe pressure should be maintained according to a pressure schedule determined prior to the start-up procedure until the kill mud weight reaches the bit. Once the kill mud weight has reached the bit, the drill pipe pressure is held constant until the annulus has been circulated free of formation fluids. This too is the identical procedure used on surface BOP stack arrangements. No special procedures are suggested when the kick reaches the sea floor.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The following conclusions can be drawn as a result of this investigation:

1. An increasing number of wells are being drilled each year in record water depths.

2. There are a limited number of floating drilling vessels currently available to drill in deep waters. Only those vessels equipped with dynamic positioning have drilled in deep waters.

3. No modifications have been made to the subsea equipment contained on these drilling vessels used to drill in deep waters. The wells drilled in deep waters have all used a 16-3/4" BOP stack rated at 10,000 psi, using Cameron ram-type preventers and Hydril or Shaffer annular-type preventers.

4. No special procedures or special training are provided to drilling personnel for drilling in deep waters. The U.S.G.S. training requirements address only surface and subsea BOP stack arrangements, regardless of water depth.

5.2 Recommendations

1. In order to drill in deep water, a dynamically positioned drilling vessel should be used

2. The internal diameter of the choke and kill lines should be enlarged to insure minimum pressure losses while circulating thru these lines during well control operations.

3. Structural and conductor casings should be set at deeper formation depths to provide greater formation fracture pressures.

Appendix

Ben Ocean Lancer

ODECO/Ben Line Offshore Contractors

Constructed by Scott-Lithgow, Scotland; 1976.

Performance: Water depth - 3,000'; Drilling depth - 20,000'.

Subsea Equipment:

Riser - 18-5/8" Riser with a multiplex electro-hydraulic control system.

Blowout Preventer - 16-3/4", 10,000 psi BOP stack consisting of two double rams, a lower riser package with 5,000 psi annular preventer.

Special Features and Equipment:

Positioning - Dynamically positioned by five 1,750-hp transversal-mounted thrusters.

Reentry - Acoustic, sonar/TV reentry systems.

Appendix

Discoverer Seven Seas

The Offshore Company

Constructed by Mitsui, Japan; 1976.

Performance: Water depth - 4,500'; Drilling depth - 25,000'.

Subsea Equipment:

Riser - 4500 feet of Regan type FCF-8, 18-5/8" O.D., 0.688 inch wall thickness. Special 42 inch floatation cans, with adjustable air columns. All riser components suitable for H2S service. Two 50 foot stroke Regan telescopic joints, one with a hydraulic drive rotating mechanism.

Blowout Preventer - 16-3/4 inch 10,000 psi system consisting of 2 Cameron double "U" preventers, 2 Hydril GL annular preventers, 2 Vetco H-4 hydraulic connectors and a special design Vetco flex joint in lieu of a standard pressure balanced ball joint.

BOP Control System - Stewart & Stevenson multiplex system with acoustic back-up.

Special Features and Equipment:

Positioning - Dynamically positioned with six 3,000 HP Bird Johnson controllable pitch right angle thrusters and twin main propulsion screws. Station keeping controlled by Honeywell computerized Automatic Station Keeping system (ASK), using acoustic reference with hard wired ball joint angle indicators as back-up sensors.

Guidelineless Reentry - Hydro products Model STV-145 combination Sonar/TV reentry tool system. Honeywell RS5 serves as backup.

BOP Control System - Blowout preventer control is a Koomey Hydraulic Sub-Sea B.O.P. Control System with the following components: Master electric drillers control panel, Merc-15 electric remote control panel, Model 26300-3S Koomey accumulator unit with 245 gallon mix-fluid reservoir, 100 gallon soluble oil reservoir, two model 88660 air powered pumps, one

Appendix (continued)

model T360-60-3 electric driven triplex pump, Model U3K-19M1/4-1M Hydraulic Control Manifold, 50 eleven gallon, 3000 psi W. P. separator type accumulator bottles, two Model RHCS-13-11 8DF Koomey double female retreivable control pods, two hose reels with 2000 feet of control hose and diverter control panel The choke manifold is 3-1/16" - 10,000 psi W. P. having an "H-2" adjustable choke, two "H2" positive chokes and one hydraulic operated SWACO super adjustable choke.

Appendix

Discoverer 534

The Offshore Company

Constructed by Mitsui, Japan; 1975.

Performance: Water depth - 3,000' ; Drilling depth-25,000'.

Subsea Equipment:

Riser - Regan 18-5/8" diameter with 18-5/8" connectors and integral buoyancy modules for 3,000 feet of water.

Blowout Preventer - Vetco-built stack with H4 connectors, 16-3/4"; 10,000 psi Cameron rams; 5,000 psi Hydril "GL" annular B.O.P.'s; trimmed for H_2S.

BOP Control System - Koomey, model 36240-3S dual redundant hydraulic system with acoustic backup.

Special Features and Equipment:

Stationkeeping System - Complete Honeywell ASK system w/RS5 position reference.

Appendix

Pelerin

Helmer Staubo & Co.

Constructed by IHC Gusto, Rotterdam; 1976.

Performance: Water depth - 3,300'; Drilling depth - 20,000'.

Subsea Equipment:

Riser - 18-5/8" diameter Cameron riser system with EG 47 T Mannesman pipes, integral choke, kill and booster lines, 5/8" riser wall thickness. Ten IHC riser tensioners, 80,000 lbs. each, 50 feet stroke with two inch cables. CIW deep water universal ball joint and 60 ft. stroke telescopic joint. Emerson & Cuming flotation modules 48 in. diameter, .48 SG, net buoyancy of riser system .0975.

Blowout Preventer - Two Rucker-Shaffer bag type 16-3/4 inch 10,000 psi bottom, 5,000 psi top. One Cameron Iron Works type U double unit BOP stack 16-3/4" 10,000 psi one 5,000 psi swivel assembly atop stack.

BOP Control System - Koomey-Matra electro-hydraulic with non-retrievable pods. Operation by multiplex Matra Tesuma system.

Special Features and Equipment:

Dynamic Positioning - CIT-Alcatel dual AMS-SP acoustic w/two CD 1700 digital computers and one Thompson-CSF analog computer.

Reentry - Subsea TV equipment - Thompson-CSF

Appendix

Penrod 74

Penrod Drilling Company

Constructed by Far East Ship-building; 1974

Performance: Water depth - 2,000';Drilling depth - 30,000'

Subsea Equipment:

Riser - The riser is 20 inch OD x 1/2 inch wall X-52 pipe with National connectors and integral kill and choke lines. It is 2,080 feet total, as follows:
Twenty 50 foot joints with buoyancy modules to provide 5% negative buoyancy.
Twenty 50 foot regular joints and two each 25', 10', and 5' regular joints.
The slip joint has a 45' stroke.

Diverter - Regan type KFDS Diverter with the following: Support housing permanently mounted under the 49 1/2 inch rotary table, KFD diverter nominal 20 inch with ten inch bore insert packer, flow line spacer spool with two hydraulic actuated seals and a type DR-1 support ball.

Blowout Preventer - The stack is a combination of 18-3/4 inch, 10,000 psi W.P. Cameron type "U" double preventers and 21-1/4 inch, 5,000 psi W.P. Rucker-Shaffer spherical blowout preventers. Starting at the wellhead and going up, the stack will have a National 18-3/4" - 10,000 psi W.P. auto lock connector; Cameron type "U" 18-3/4" - 10,000 psi W.P. double with 5" pipe rams in top and bottom; Cameron type "U" 18-3/4" - 10,000 psi W.P. double with new style blind/shear rams in bottom and blind rams in top; Rucker-Shaffer 21-1/4" - 5,000 psi WP spherical blowout preventer; National 18-3/4" - 10,000 psi W.P. 15 deg. tapered auto lock connector; Rucker-Shaffer 21-1/4" - 5,000 psi W.P. spherical blowout preventer; 18-3/4" nominal National single ball hydra-ball joint with National 20" nominal female riser lock connector. There are 12 eleven gallon, 3,000 psi W.P. separator type accumulator bottles mounted on the stack. The stack mounted choke and kill valves are Cameron type "F" gate double 90 degree block tee, with 3-1/8" - 10,000 psi W.P. BX - 154 clamp hub inlet and outlet, with two type "AF" failsafe 3000# operators.

Appendix

Sedco 445

Sedco Inc.

Constructed by Mitsui, Japan; 1971.

Performance: Water depth 3,500'; Drilling depth - 20,000'.

Subsea Equipment:

Riser - 4000 feet of Regan integral marine riser with 10,000 psi choke and kill lines, 3000 feet of which is equipped with Emerson and Cuming syntactic foam buoyancy modules.

Blowout Preventer - 1 16-3/4" 5,000 psi Cameron blowout preventer stack with three sets of pipe rams, one set of blind shear rams and Hydril annular preventer. 1 16-3/4" 10,000 psi Cameron blowout preventer stack with three sets of pipe rams, one set of blind shear rams and Hydril annular preventer.

BOP Control System - Koomey EH/Hydraulic BOP control system and RATAC acoustic back up.

Special Features and Equipment:

Dynamic Positioning - Honeywell Automatic Station Keeping (ASK) with redundant H316 computers, RS-5 Acoustic Position Indicators, taut wire angle sensors and riser angle indicators.

Appendix

Sedco/BP 471

Overseas Drilling Ltd.

Constructed by Halifax Shipyards Division of Hawker Siddeley Canada Ltd., Halifax, N.S., Canada; 1978.

Performance; Water depth - 4,500' (up to 6,000'); Drilling depth - 25,000'.

Subsea Equipment:

Riser - 4350 feet of Vetco integral marine riser with 10,000 psi choke and kill lines, 3000 feet of which is equipped with Emerson and Cuming syntactic foam buoyancy modules.

Blowout Preventers - 2 16-3/4" 10,000 psi Cameron blowout preventer stacks with three sets of pipe rams, one set of blind shear rams and Shaffer spherical preventer.

BOP Control System - Koomey multiplexed E/H BOP control system with E/H hard wire back up and RATAC acoustic back up.

Special Features and Equipment:

Dynamic Positioning - Honeywell Automatic Station Keeping (ASK) with redundant H316 computers, RS-7 Acoustic Position Indicators, taut wire angle sensors and riser angle indicators.

Reentry - Edo Western combined Sonar/TV reentry tool.

Appendix

Sedco 472

Sedco Inc.

Constructed by Mitsui, Japan; August, 1977.

Performance: Water depth - 4,500'; Drilling depth - 20,000'.

Subsea Equipment:

Riser - 4350 feet of Vetco integral marine riser with 10,000 psi choke and kill lines, 3,000 feet of which is equipped with Emerson and Cuming syntactic foam buoyancy modules.

Blowout Preventer - 1 16-3/4" 10,000 psi Cameron blowout preventer stack with three sets of pipe rams, one set of blind shear rams and Shaffer spherical preventer.

BOP Control System - Koomey multiplexed E/H BOP control system with E/H hard wire back up and RATAC acoustic back up.

Special Features and Equipment:

Dynamic Positioning - Honeywell Automatic Station Keeping (ASK) with redundant H316 computers, RS-7 Acoustic Position Indicators, taut wire angle sensors and riser angle indicators.

Reentry - Edo Western combined Sonar/TV reentry tool.

Appendix

Sedco 709

Marine Drilling S.A.

Constructed by Hawker Siddeley, Halifax; 1976.

Performance: Water depth - 6,000'; Drilling depth - 25,000'.

Subsea Equipment:

Riser - 3,200 feet, 18-5/8" integral with buoyancy

Blowout Preventer - 2 16-3/4", 10,000 psi blowout preventers

BOP Control System - Subsea controls, Multiplex control, 100% Redundancy

Special Features and Equipment:

Dynamic Positioning - Honeywell Automatic Station Keeping (ASK) System.

Reentry - Thru Drill Pipe TV/Sonar

Appendix

Zapata Concord

Zapata Corp.

Constructed by Avondale Shipyard, New Orleans, Louisiana; 1975.

Performance: Water depth - 2,000'; Drilling depth - 25,000'.

Subsea Equipment:

Riser - 2,000' of 21" O.D. x 20" I.D., 45' stroke slip joint; riser tensioning system by Rucker.

Blowout Preventer - Cameron 18-3/4" single stack system with two 10,000 psi W P Cameron type U double ram preventers, and two Rucker-Shaffer 18-3/4" spherical preventers.

Special Features and Equipment:

Anchoring System - Eight Vincinay Offdrill 40,000 lb anchors with eight 2,500' lengths of 2-3/4" steel stud length chain and eight 4,500' lengths of 2-3/4" wire rope.

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Son of Mr. and Mrs. Robert Surcouf Sr., Robert M. Surcouf Jr. was born in New Orleans, Louisiana, October 7, 1949.

He graduated in Engineering Sciences, May, 1971 at Louisiana State University in New Orleans.

Upon graduation, he was employed by the United States Geological Survey as a petroleum engineer.

He entered the adult continuing education program offered by Louisiana State University in the spring of 1977. He entered graduate school as a part time student in the fall of 1977 and worked towards his MS degree in Petroleum Engineering while continuing to be employed full time by the U. S. Geological Survey.

He is married to the former Beth Thompson and they have two daughters, nine-year old Becky and two-year Sarah.